AIR QUALITY DIVISION
CHAPTER 6, SECTION 3
OPERATING PERMIT

WYOMING DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION
122 West 25th Street
Cheyenne, Wyoming 82002

PERMIT NO. 3-1-083

Issue Date: **June 27, 2007**
Expiration Date: **May 10, 2009**
Effective Date: **June 27, 2007**
Replaces Permit No.: **30-083**

In accordance with the provisions of W.S. §35-11-203 through W.S. §35-11-212 and Chapter 6, Section 3 of the Wyoming Air Quality Standards and Regulations,

FMC Wyoming Corporation
FMC Granger Soda Ash
Section 36, Township 20 North, Range 111 West
Sweetwater County, Wyoming

is authorized to operate a stationary source of air contaminants consisting of emission units described in this permit. The units described are subject to the terms and conditions specified in this permit. All terms and conditions of the permit are enforceable by the State of Wyoming. All terms and conditions of the permit, except those designated as not federally enforceable, are enforceable by EPA and citizens under the Act. A copy of this permit shall be kept on-site at the above named facility.

David A. Finley, Administrator
Air Quality Division

Date: 6/27/07

John V. Corra, Director
Department of Environmental Quality

Date: 7/2/07

WAQSR CHAPTER 6, SECTION 3 OPERATING PERMIT

WYOMING DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

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GENERAL INFORMATION

Company Name: **FMC Wyoming Corporation**

Mailing Address: **P.O. Box 872**

City: **Green River** State: **Wyoming** Zip: **82935**

Plant Name: **FMC Granger Soda Ash**

Plant Location: **Section 36, Township 20 North, Range 111 West, Sweetwater County, Wyoming (7 miles NNE of Granger, WY).**

Plant Mailing Address: **FMC Granger**
c/o FMC Wyoming Corporation
Westvaco Rd., P.O. Box 872

City: **Green River** State: **Wyoming** Zip: **82935**

Name of Owner: **FMC Wyoming Corporation** Phone: **(307) 875-2580**

Responsible Official: **Jim Pearce** Phone: **(307) 872-2501**

Plant Manager/Contact: **Michael Wendorf** Phone: **(307) 872-2162**

DEQ Air Quality Contact: **District 5 Engineer** Phone: **(307) 332-6755**
510 Meadowview Drive
Lander, Wyoming 82520

SIC Code: **1474**

Description of Process: **Production of purified soda ash (sodium carbonate, $NaCO_3$) from trona ore and/or mine water feedstock from the location's trona mine.**

SOURCE EMISSION POINTS

This table may not include any or all insignificant activities at this facility.

SOURCE ID#	SOURCE DESCRIPTION	SIZE	CH. 6, SEC. 2 PERMITS
01	Ore Transfer Conveyor with baghouse control	461 TPH	OP-222
03	Ore Crusher/Screening with baghouse control	383 TPH	OP-222
04	#1 Ore Calciner with ESP control	175 TPH	MD-462A, OP-268
05	#2 Ore Calciner with ESP control	175 TPH	MD-462A, OP-268
07	#1 Product Dryer with scrubber control	91 TPH	MD-462A, OP-222
08	#2 Product Dryer with scrubber control	91 TPH	MD-462A, OP-222
09	#1 Product Sizing with baghouse control	91 TPH	OP-222
10	#2 Product Sizing with baghouse control	91 TPH	OP-222
11	Product Handling with baghouse control	155 TPH	OP-222
12	Product Silos with baghouse control	155 TPH	OP-222
13	Product Loadout with baghouse control	480 TPH	OP-222
14	#1 Coal-Fired Boiler with FGD scrubber and ESP control	358.5 MMBtu/hr	OP-222
15	#2 Coal-Fired Boiler with FGD scrubber and ESP control	358.5 MMBtu/hr	OP-222
16	Ash Handling System with baghouse control	38 TPH	OP-222
18	Mine Skip Unloading with baghouse control	489 TPH	OP-222
19	Emergency Fire Pump Engine	1.86 MMBtu/hr	None
20	Emergency Mine Generator	12.74 MMBtu/hr	None
21	Emergency Plant Generator	6.86 MMBtu/hr	None
22	Perlite Storage Silo with a bin vent	40 ton	OP-222
23	Limestone Storage Silo with a bin vent	50 ton	OP-222
24	Fluid Bed Product Dryer with scrubber control	18.6 TPH	MD-462A, OP-222
27	Lime Storage Silo – Leach with a bin vent	130 ton	OP-222
28	Lime Storage Silo – Deca with a bin vent	90 ton	November 24, 1989 Waiver
29	Trona Ore Stockpile Activities	N/A	OP-222
30	Coal Stockpile Activities	N/A	OP-222
32	Diesel Equipment Fuel Tanks (2)	12,000 gal each	None

SOURCE ID#	SOURCE DESCRIPTION	SIZE	CH. 6, SEC. 2 PERMITS
33	Boiler Fuel Oil Tank	30,566 gal	None
34	Unleaded Gas Tank	12,250 gal	None
35	Unleaded Gas Tank	8,695 gal	None
36	Hydrochloric Acid Tank	10,000 gal	None
37	Cooling Tower – Soda Ash	373 MMBtu	None

TOTAL FACILITY ESTIMATED EMISSIONS

For informational purposes only. These emissions are not to be assumed as permit limits.

POLLUTANT	EMISSIONS (TPY)
CRITERIA POLLUTANT EMISSIONS	
Particulate Matter	721
PM_{10} Particulate Matter	710
Sulfur Dioxide (SO_2)	637
Nitrogen Oxides (NO_X)	2504
Carbon Monoxide (CO)	2523
Volatile Organic Compounds (VOCs)	716
HAZARDOUS AIR POLLUTANT (HAP) EMISSIONS	212

Emission estimates are based on allowable emissions from permits MD-462A, OP-222; waivers AP-3297 and from 11/24/89; and estimated emissions in the operating permit application, including fugitive emissions.

FACILITY-SPECIFIC PERMIT CONDITIONS

Facility-Wide Permit Conditions

(F1) PRODUCTION RATE LIMITS [WAQSR Ch 6, Sec 2 Permit MD-462A]
The maximum soda ash production through the dryers (units 07, 08 & 24) shall be limited to 1.3 million tons per year (MM TPY) from no more than 2.63 MM TPY of trona ore.

(F2) SULFUR DIOXIDE EMISSIONS INVENTORY [WAQSR Ch 14, Sec 3]
The permittee shall report SO_2 emissions annually as required by WAQSR Chapter 14, Section 3. SO_2 emissions shall be estimated in accordance with Chapter 14, Section 3(b), and adjusted in accordance with Chapter 14, Section 3(c) if necessary.

Source-Specific Permit Conditions

(F3) VISIBLE EMISSIONS [40 CFR Part 60, Subpart D and WAQSR Ch 3, Sec 2]
- (a) Visible emissions from the #1 and #2 coal-fired boilers (units 14 & 15) shall not exceed 20 percent opacity except for one (1) six-minute period of not more than 27 percent opacity.
- (b) Visible emissions from the emergency fire pump engine, the emergency mine generator, and the emergency plant generator (units 19, 20 & 21) shall not exceed 30 percent opacity except for periods not exceeding ten consecutive seconds. This limitation shall not apply during a reasonable period of warm-up following a cold start or where undergoing repairs and adjustment following a malfunction.
- (c) Unless a lower limit is specified elsewhere in this permit, visible emissions of any contaminant discharged into the atmosphere from any other single emission source shall not exhibit greater than 20 percent opacity except for one period or periods aggregating not more than six minutes in any one hour of not more than 40 percent opacity.

(F4) FUGITIVE EMISSIONS [WAQSR Ch 6, Sec 2 Permit OP-222 and Waiver AP-3297]
- (a) The permittee shall control fugitive emissions from the coal stock pile (unit 30), by applying a dust suppressant chemical in accordance with the October 28, 1987 plan, or by revised methods submitted and approved by the Division.
- (b) The permittee shall control fugitive emissions from the rail delivery and plant receiving hopper coal handling operations by using chemical wet spray systems in accordance with the October 28, 1987 plan, or by methods submitted and approved by the Division.
- (c) The fugitive emission control plan is described in Appendix A of this permit.
- (d) The permittee shall control fugitive emissions from the trona ore stockpile activities (unit 29) by watering the equipment operations path during all stockpiling and reclamation activities. A standard of 20 percent opacity shall be used to define acceptable fugitive dust control.
- (e) The permittee shall control fugitive dust emissions from wind erosion and vehicular traffic on the Granger Road and the plant service road with chemical dust suppressants in addition to water. At a minimum, two (2) applications of dust suppressant shall be applied annually, once in the spring and once in the fall. The Granger Road and the plant service road shall be maintained continuously to the extent that such treatment remains a viable control measure, which may require additional application of chemical dust suppressant.

(F5) PARTICULATE EMISSION LIMITS
[WAQSR Ch 6, Sec 2 Permits MD-462A & OP-222; 40 CFR Part 60, Subpart D; and WAQSR Ch 6, Sec2 November 24, 1989 Waiver]
- (a) Particulate emissions from the #1 and #2 coal-fired boilers (units 14 & 15) shall not exceed 0.10 pounds per million Btu (lb/MMBtu) each.
- (b) Particulate emissions from the units listed in Table 1 of this permit shall not exceed the specified limits.

TABLE I: Particulate Emission Limits		
Source ID#	Source Description	PM_{10} Emission Limits pounds per hour (lb/hr)
01	Ore Transfer Conveyor	1.03
03	Ore Crusher/Screening	2.14
04	#1 Ore Calciner	15.80
05	#2 Ore Calciner	15.80
07	#1 Product Dryer	3.94
08	#2 Product Dryer	3.94
09	#1 Product Sizing	2.57
10	#2 Product Sizing	2.57
11	Product Handling	2.57
12	Product Silos	2.57
13	Product Loadout	1.31
14	#1 Coal-Fired Boiler [1]	35.85
15	#2 Coal-Fired Boiler [1]	35.85
16	Ash Handling System	0.43
18	Mine Skip Unloading	1.33
22	Perlite Storage Silo	0.07
23	Limestone Storage Silo	0.07
24	Fluid Bed Product Dryer	1.00
27	Lime Storage Silo – Leach	0.07
28	Lime Storage Silo – Deca	0.14

[1] 0.10 lb/MMBtu of heat input from 40 CFR Part 60, Subpart D, not to exceed 35.85 lb/hr from WAQSR Ch 6, Sec 2 Permit OP-222.

(F6) SO_2 AND NO_X EMISSION LIMITS
[WAQSR Ch 6, Sec 2 Permits MD-462A and OP-268; 40 CFR Part 60, Subpart D]
Emissions from the units listed in Table II of this permit shall not exceed the specified limits.

TABLE II: NO_X and SO_2 Emission Limits					
Source ID#	Source Description	SO_2 Emission Limits		NO_X Emission Limits	
		lb/MMBtu	lb/hr	lb/MMBtu	lb/hr
04	#1 Ore Calciner		0.00	0.15	30.00
05	#2 Ore Calciner		0.00	0.15	30.00
14	#1 Coal-Fired Boiler	1.2[1]	71.70	0.70	250.95
15	#2 Coal-Fired Boiler	1.2[1]	71.70	0.70	250.95

[1] See condition S4 of this permit for the more stringent State lb/MMBtu SO_2 emission limit.

(F7) OPERATIONAL REQUIREMENTS [WAQSR Ch 6, Sec 2 Permit MD-462A and W.S. 35-11-206]

(a) The permittee shall operate the calciner burners (units 04 & 05) according to the June 13, 1995 operational plan for CO minimization. The calciner burner operational plan is provided in Appendix B of this permit.

(b) Units 22, 23 and 27 shall be limited to 500 hours of annual operations.

(F8) PROCESS RATES AND STOCKPILE SIZE LIMITS [WAQSR Ch 6, Sec 2 Permits MD-462A and OP-222]

(a) The #1 and #2 ore calciners (units 04 & 05) shall be operated at production rates which do not exceed the following limits:

(i) 165 tons per hour (TPH) instantaneous maximum production throughput for each individual calciner when both calciners are operating; or

(ii) 175 TPH instantaneous maximum trona ore throughput for each individual calciner during periods when one calciner is shut down (single calciner operation).

(b) The plant dryers (units 07, 08 & 24) shall be operated at production rates which do not exceed the following limits:

(i) The #1 and #2 product dryers (units 07 & 08) shall each be limited to a soda ash production rate of 91.0 TPH;

(ii) The #1 and #2 product dryers (units 07 & 08) shall be limited to a combined dryer annual soda ash production rate of 1.2 MM TPY; and

(iii) The fluid bed dryer (unit 24) shall be limited to soda ash production rates of 18.6 TPH and 0.1 MM TPY.

(c) The maximum size of the active trona ore stockpile shall not exceed 350,000 tons, while the maximum size of the reserve trona ore stockpile shall not exceed 150,000 tons. The maximum annual throughput of the active ore stockpile shall not exceed 600,000 TPY.

Testing Requirements

(F9) PARTICULATE EMISSIONS TESTING [WAQSR Ch 6, Sec 2 Permit OP-268 and W.S. 35-11-110]

(a) The permittee shall test the #1 and #2 ore calciners (units 04 & 05) at least once during the term of this permit to assess compliance with the particulate emission limits set in condition F5 of this permit.

(i) The test shall be performed within 12 months of startup of the unit(s).

(ii) During the test(s) the permittee shall simultaneously monitor the opacity from each stack to verify the relationship between particulate matter emissions and opacity for each unit.

(iii) Testing shall consist of a Reference Method 5 sampling train with back half impinger catch analyzed by the protocol defined by Reference Method 202.

(iv) To determine compliance, the sum of the Method 5 front half particulate catch and the inorganic (mineral) portion of the Reference Method 202 back half of the Method 5/202 tests, will be compared to the particulate emission limits set in condition F5 of this permit.

(b) The permittee shall test the #1 and #2 product dryers and the fluid bed product dryer (units 07, 08 & 24) at least once during the term of this permit to assess compliance with the particulate emission limits set in condition F5 of this permit.

(i) The test shall be performed within 12 months of the date of issuance of this permit.

(ii) During the test the permittee shall simultaneously monitor the pressure differential across each scrubber and the liquor flows for each scrubber to verify the relationship between particulate matter emissions, pressure differential and liquor flow for each unit.

(iii) Testing shall consist of Reference Method 5 with back half impinger catch analyzed by the protocol defined by Reference Method 202.

(c) The permittee shall test the #1 and #2 coal-fired boilers (units 14 & 15) annually at a minimum to assess compliance with the particulate emission limits set in condition F5 of this permit.

(i) Particulate emissions testing shall be conducted as specified in 40 CFR Part 60, Subpart D §60.46.

(ii) During the test the permittee shall simultaneously monitor the opacity from each stack to verify the relationship between particulate matter emissions and opacity for each unit.

(d) The permittee shall provide the Division at least 15 days prior notice of any anticipated test date.

(e) Unless otherwise specified, testing shall be conducted in accordance with WAQSR Ch 5, Sec 2(h).

(F10) ADDITIONAL TESTING [WAQSR Ch 6, Sec 2 Permit OP-268; W.S. 35-11-110; and 40 CFR Part 60, Subpart D]

(a) The Division reserves the right to require additional testing as provided under condition G1 of this permit. Should testing be required:

(i) For particulate emissions, SO_2 emissions, NO_X emissions and visible emissions from the #1 and #2 coal-fired boilers (units 14 & 15), methods as specified in 40 CFR Part 60, Subpart D §60.46 shall be used.

(ii) For particulate emissions from the trona processing sources, testing shall consist of a Reference Method 5 sampling train with back half impinger catch analyzed by the protocol defined by Reference Method 202. To determine compliance for any particular stack, compare the sum of the Method 5 front half particulate catch and the inorganic (mineral) portion of the Reference Method 202 back half of the Method 5/202 tests, against the particulate emission limits set in condition F5 of this permit.

(iii) For visible emissions from other sources, Method 9 shall be used.

(iv) For NO_X emissions from other sources, Methods 1-4, and 7 or 7E shall be used.

(v) For SO_2 emissions from sources other sources, Methods 1-4 and 6 or 6C shall be used.

(vi) For CO emission sources, Methods 1-4 and 10 shall be used.

(vii) For alternative test methods, or methods used for other pollutants, the approval of the Administrator must be obtained prior to using the test method to measure emissions.

(b) The permittee shall provide the Division at least 15 days prior notice of any anticipated test date.

(c) Unless otherwise specified, testing shall be conducted in accordance with WAQSR Ch 5, Sec 2(h).

Monitoring Requirements

(F11) VISIBLE EMISSIONS MONITORING
[WAQSR Ch 6, Sec 3(h)(i)(C)(I); and WAQSR Ch 6, Sec 2 Permit OP-268]

(a) Periodic monitoring of visible emissions from #1 and #2 coal-fired boilers (units 14 & 15) shall consist of the Continuous Opacity Monitoring systems (COMs) described in P60-D2 of this permit.

(b) Periodic monitoring of visible emissions from the electrostatic precipitator controlled calciner stacks (units 04 & 05) shall consist of COMs. The COMs shall be calibrated and operated as described in WAQSR Chapter 5, Section 2 (j).

(c) Periodic monitoring of visible emissions from the perlite storage silo, limestone storage silo, lime storage silo-leach, and lime storage silo-deca (units 22, 23, 27 & 28) shall consist of quarterly visual observations of each baghouse or bin vent stack, while the unit is in operation, to determine the presence of visible emissions.

(i) The visual observations shall be conducted by a person who is educated on the general procedures for determining the presence of visible emissions but not necessarily certified to perform Method 9 observations.

(ii) Observation of visible emissions from any baghouse or bin vent shall prompt immediate inspection and, if necessary, corrective actions.

(d) Periodic monitoring of visible emissions from the remaining units with particulate emission limits (units 01, 03, 07, 08, 09, 10, 11, 12, 13, 16, 18 & 24) shall consist of the Compliance Assurance Monitoring (CAM) outlined under condition F13 of this permit.

(F12) FUGITIVE EMISSIONS MONITORING [WAQSR Ch 6, Sec 3(h)(i)(C)(I)]

(a) The permittee shall monitor the amount of dust suppressant chemical(s) used for control of fugitive emissions from the coal stock pile (unit 30) and the rail delivery and plant receiving hopper handling operations.

(b) The permittee shall monitor the amount of water used to control fugitive emissions from the trona ore stockpile activities (unit 29).

(c) The permittee shall monitor the amount of dust suppressant or water applied to the Granger Road and the plant service road, including the date of application.

(F13) PARTICULATE EMISSION AND COMPLIANCE ASSURANCE MONITORING
[WAQSR Ch 6, Sec 3(h)(i)(C)(I); and Ch 7, Sec 3(i)(ii)]

(a) Periodic monitoring of particulate emissions from the perlite storage silo, limestone storage silo, and the lime storage silo (units 22, 23, 27 & 28), is not required since particulate emissions from these sources are of trivial environmental importance.

(b) The permittee shall adhere to the individual compliance assurance monitoring (CAM) plans for particulate emissions attached as Appendix C of this permit and shall conduct monitoring as follows:
   (i) For the venturi scrubber controlled product dryers (units 07, 08, and 24) the permittee shall monitor the pressure ranges across the scrubbers and the liquor flows at minimum, once daily.
   (ii) For the baghouse controlled units (units 01, 03, 09, 10, 11, 12, 13, 16, and 18) the permittee shall monitor the visible emissions from the stack at a minimum, once daily.
   (iii) For the electrostatic precipitator controlled calciners (units 04 and 05) the permittee shall continuously monitor the opacity from each stack as required by condition F11(b).
   (iv) For the electrostatic precipitator controlled coal fired boilers (units 14 and 15) the permittee shall continuously monitor the opacity from the stack as described in condition P60-D2.
   (v) Operation outside of the ranges established in the approved CAM plan(s) shall trigger immediate corrective action.
   (vi) The permittee shall follow all other applicable requirements under conditions CAM-1 through CAM-4 of this permit.

(F14) SO_2 AND NO_X EMISSION MONITORING [WAQSR Ch 6, Sec 3(h)(i)(C)(I)]

(a) Periodic monitoring of SO_2 and NO_X emissions from the #1 and #2 coal-fired boilers (units 14 & 15) shall consist of the continuous emissions monitoring described in condition P60-D2 of this permit.

(b) Periodic monitoring of NO_X emissions from the #1 and #2 ore calciners (units 04 & 05) shall consist of NO_X emissions testing conducted at least annually. The permittee shall measure NO_X emissions using reference method tests as described in condition F10 of this permit.

(c) Periodic monitoring for SO_2 emissions from the #1 and #2 ore calciners (units 04 & 05), is not required since SO_2 emissions from these natural gas fired sources are not expected.

(F15) OPERATIONAL MONITORING [WAQSR Ch 6, Sec 3(h)(i)(C)(I)]
On a monthly basis, the permittee shall monitor the year to date, hours of operation of units 22, 23 and 27 for comparison with the annual hours of operation limit in condition F7 of this permit.

(F16) PRODUCTION RATE, PROCESS RATES AND STOCKPILE SIZE MONITORING
[WAQSR Ch 6, Sec 3(h)(i)(C)(I)]

(a) On a monthly basis the permittee shall monitor the year to date, soda ash production and trona ore throughput for comparison with the limits set in condition F1 of this permit.

(b) On a monthly basis the permittee shall monitor the #1 and #2 ore calciners (units 04 & 05) and the plant product dryers (units 07, 08 & 24) process rates, for comparison with the annual process rate limits in condition F8 of this permit.

(c) On a monthly basis the permittee shall estimate the size of the active trona ore stockpile, the reserve trona ore stockpile and the year to date annual throughput of the active ore stockpile for comparison with the limits in condition F8 of this permit.

(F17) AMBIENT PARTICULATE MONITORING [EPA Permit 8A-EE and WAQSR Ch 6, Sec 3(h)(i)(C)(I)]
The permittee shall operate a Division approved, ambient particulate monitoring network in accordance with the requirements of 40 CFR Parts 50 and 58.

Recordkeeping Requirements

(F18) SULFUR DIOXIDE EMISSIONS INVENTORY RECORDS [WAQSR Ch 14, Sec 3(b)]

(a) The permittee shall maintain all records used in the calculation of SO_2 emissions, including but not limited to the following:
   (i) Amount of fuel consumed;
   (ii) Percent sulfur content of fuel and how the content was determined;

(iii) Quantity of product produced;
(iv) Emissions monitoring data;
(v) Operating data; and
(vi) How the emissions are calculated, including monitoring/estimation methodology with a demonstration that the selected methodology is acceptable under Chapter 14, Section 3.

(b) The permittee shall maintain records of any physical changes to facility operations or equipment, or any other changes (e.g. raw material or feed) that may affect emissions projections of SO_2.

(c) The permittee shall retain all records and support information for compliance with this condition and with the reporting requirements of condition F26 at the facility, for a period of **at least ten (10) years** from the date of establishment, or if the record was the basis for an adjustment to the milestone, five years after the date of an implementation plan revision, whichever is longer.

(F19) VISIBLE EMISSIONS RECORDS [WAQSR Ch 6, Sec 3(h)(i)(C)(II); Ch 6, Sec 2 Permit OP-268; and Ch 5, Sec 2(g)]

(a) Records of visible emissions monitoring for the #1 and #2 coal-fired boilers (units 14 & 15) are described in condition P60-D3 of this permit.

(b) For the quarterly visible emissions monitoring from the perlite storage silo, limestone storage silo, and the lime storage silo-leach, and the lime storage silo-deca (units 22, 23, 27 & 28) required under condition F11, the permittee shall record, as applicable, the following:
(i) The date, place, and time of the observation;
(ii) The company or entity that performed the observation;
(iii) The observation techniques or methods used;
(iv) The results of the observation; and
(v) The operating conditions as they existed at the time of the observation.

(c) For the COM systems on the calciner stacks (units 04 & 05), records shall be maintained of all measurements from the COM systems, performance testing measurements, performance audits, calibration checks, and maintenance performed on the system in accordance with the requirements of WAQSR Chapter 5, Section 2 (g).

(d) The permittee shall retain on-site at the facility, the records kept in accordance with this condition, and support information for a period of at least five years from the date such records are generated.

(F20) FUGITIVE EMISSIONS RECORDS [WAQSR Ch 6, Sec 3(h)(i)(C)(II); and Ch 6, Sec 2 Waiver AP-3297]

(a) For fugitive emissions from the coal stock pile (unit 30), and the rail delivery and plant receiving hopper handling operations, the permittee shall record the type of chemical used, including manufacturer and specification, and the annual usage rates in gallons, such that compliance with condition F4(a) and (b) of this permit may be determined.

(b) For fugitive emissions from the trona ore stockpile activities (unit 29), the permittee shall record the amount of water used, and the annual usage rated in gallons, such that compliance with condition F4(d) of this permit may be determined.

(c) The permittee shall record the date and amount of chemical dust suppressant and/or water applied to the Granger Road and the plant service road.

(d) The permittee shall retain the records on-site at the facility for a period of at least five years from the date such records are generated.

(F21) PARTICULATE EMISSION AND COMPLIANCE ASSURANCE MONITORING RECORDS [WAQSR Ch 6, Sec 3(h)(i)(C)(II) and Ch 7, Sec 3 (i)(ii)]

(a) For the CAM of particulate emissions required under condition F13(b)(i) for units 07, 08 & 24, the permittee shall record, at minimum once daily, the pressure range across each scrubber and the liquor flow of each scrubber.

(b) For the CAM of particulate emissions required under condition F13(b)(ii) for units 01, 03, 09, 10, 11, 12, 13, 16 & 18, the permittee shall record, at minimum once daily, the visible emission results from the stack of each baghouse unit.

(c) For the CAM of particulate emissions required under condition F13(b)(iii) for units 04 & 05, the opacity records maintained under F19(c) are sufficient.

(d) For the CAM of particulate emissions required under condition F13(b)(iv) for unit 14 & 15, the opacity monitoring records maintained under 40 CFR, Subpart D are sufficient.

(e) The permittee shall also maintain records of monitoring data, monitor performance data, corrective actions taken, any written Quality Improvement Plan (QIP) required pursuant to WAQSR Chapter 7, Section 3(h), any activities undertaken to implement a QIP, and other supporting information required to be maintained under WAQSR Chapter 7, Section 3.

(f) The permittee shall retain on-site at the facility, the records of each test, measurement, observation, and support information for a period of at least five years from the date of the test, measurement, or observation.

(F22) TESTING, NO_X AND SO_2 EMISSIONS MONITORING RECORDS [WAQSR Ch 6, Sec 3(h)(i)(C)(II)]

(a) For any testing required under conditions F9 or F10 of this permit and the emissions monitoring required under condition F14, other than Method 9 observations, the permittee shall record, as applicable, the following:

(i) The date, place, and time of sampling or measurements;
(ii) The date(s) the analyses were performed;
(iii) The company or entity that performed the analyses;
(iv) The analytical techniques or methods used;
(v) The results of such analyses; and
(vi) The operating conditions as they existed at the time of sampling or measurement.

(b) For any Method 9 observations required by the Division under condition F10, the permittee shall keep field records in accordance with Section 2.2 of Method 9. Any corrective measures taken shall also be recorded.

(c) For the SO_2 and NO_X emissions monitoring from the #1 and #2 coal-fired boilers (units 14 & 15), the permittee shall keep records in accordance with condition P60-D3 of this permit.

(d) The permittee shall retain on-site at the facility the records of each test, measurement, or observation and support information for a period of at least five years from the date of the test, measurement, or observation.

(F23) OPERATIONAL RECORDS [WAQSR Ch 6, Sec 3(h)(i)(C)(II)]

(a) The permittee shall record any deviations from the operational plan for CO minimization for the calciner burners.

(b) The permittee shall record the year to date operating hours of operation of units 22, 23 and 27, on a monthly basis.

(c) The permittee shall retain on-site at the facility the records of deviation and annual hours of operations for a period of at least five years from the date of the record.

(F24) PRODUCTION RATE, PROCESS RATES AND STOCKPILE SIZE RECORDS [WAQSR Ch 6, Sec 3(h)(i)(C)(II)]

(a) On a monthly basis the permittee shall record the year to date soda ash production and trona ore throughput.

(b) The permittee shall record the date, times, and duration during which any process rate of the #1 and #2 ore calciners (units 04 & 05) and the plant product dryers (units 07, 08 & 24) exceeded the respective limits in condition F8 of this permit.

(c) On a monthly basis, the permittee shall record the estimated size of the active trona ore stockpile, the reserve trona ore stockpile and the year to date annual throughput of the active ore stockpile.

(d) The permittee shall retain on-site at the facility all records kept in accordance with the requirements of this condition for a period of at least five years from the date of the record.

(F25) AMBIENT PARTICULATE MONITORING RECORDS [WAQSR Ch 6, Sec 3(h)(i)(C)(II)]

(a) The permittee shall maintain records of the data generated by the ambient particulate monitoring program in accordance with the "Quality Assurance Plan" submitted to the Division February 18, 1999 or the most recent Division approved plan.

(b) The permittee shall retain on-site at the facility the ambient monitoring records kept in accordance with the requirements of this condition for a period of at lease five years from the date of the record.

Reporting Requirements

(F26) SULFUR DIOXIDE EMISSIONS INVENTORY REPORTS [WAQSR Ch 14, Sec 3(b) and (c)]

(a) The permittee shall report calendar year SO_2 emissions by April 15th of the following year. The inventory shall be submitted in the format specified by the Division.

(b) Emissions from startup, shutdown, and upset conditions shall be included in the inventory.

(c) If the permittee uses a different emission monitoring or calculation method than was used to report SO_2 emissions in 1998, the permittee shall adjust reported SO_2 emissions to be comparable to the emission monitoring or calculation method that was used in 1998. The calculations that are used to make this adjustment shall be included with the annual emission report.

(d) The annual reports shall be submitted in accordance with condition G4 of this permit.

(F27) VISIBLE EMISSIONS, EXCESS OPACITY AND MONITORING SYSTEM PERFORMANCE REPORTS [WAQSR Ch 6, Sec 3(h)(i)(C)(III); Ch 6, Sec 2 Permit OP-222; and Ch 5, Sec 2(g)]

(a) Excess emissions and monitoring system performance reports for the #1 and #2 coal-fired boilers (units 14 & 15) are described in condition P60-D4 of this permit.

(b) The permittee shall report to the Division by January 31 and July 31 each year the summary results of the weekly baghouse emissions monitoring required under condition F11(c) of this permit (units 22, 23, 27 & 28). Only monitoring during which visible emissions are observed and any corrective actions taken upon observing visible emission shall be included in the report. If no visible emissions are observed during the reporting period, this shall be stated in the report.

(c) Excess emission reporting for the COM systems on the calciner stacks (units 04 & 05), shall comply with the requirements of the WAQSR Chapter 5, Section 2(g). For the purpose of reporting under this condition, excess emissions for the calciners are defined as any six (6) minute period when the average opacity exceeds 20 percent.

(d) For the calciners (units 04 & 05), the permittee shall submit an excess opacity and monitoring systems performance report to the Administrator quarterly. All reports shall be postmarked by the 30th day following the end of each calendar quarter. Written reports of excess emission shall be in a format approved by the Division and shall include the following information:

   (i) The magnitude of excess emission computed in accordance with Chapter 5, Section 2(j)(viii), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

   (ii) Specific identification of each period of excess emissions that occurs during start-ups, shutdowns, malfunctions of the calciners (units 04 & 05). The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

   (iii) The date and time identifying each period during which either COM system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

   (iv) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

   (v) One summary report form for the opacity monitored at each affected facility.

      (A) If the total duration of excess emissions for the reporting period is less than one percent (1%) of the total operating time for the reporting period and the COM system downtime for the reporting period is less than five percent (5%) of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in paragraph (d) of this condition need not be submitted unless requested by the Administrator.

      (B) If the total duration of excess emissions for the reporting period is 1% or greater of the total operating time for the reporting period and the COM system downtime for the reporting period is 5% or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in paragraph (d) of this condition shall both be submitted.

(e) Notwithstanding the frequency of reporting requirements specified in paragraph (d) of this condition, a permittee who is required to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual as described in WAQSR Chapter 5, Section 2(g)(iv). Any reduction in the reporting frequency required a significant modification to this operating permit pursuant to WAQSR Chapter 6, Section 3(d)(vi)(C).

(f) The reports shall be submitted to the Division in accordance with condition G4 of this permit.

(F28) ANNUAL FUGITIVE EMISSIONS REPORTS [WAQSR Ch 6, Sec 2 Permit OP-222; and Ch 6, Sec 3(h)(i)(C)(iii)]

(a) The following shall be reported to the Division within 60 days of the end of each calendar year:

(i) An annual summary on the fugitive emissions control measures applied to the coal stock pile (unit 30), and the rail delivery and plant receiving hopper handling operations. The report shall include the type of chemical used, including manufacturer and specification, and the annual usage in gallons.

(ii) An annual summary on watering activities for the trona ore stockpile activities (unit 29).

(iii) An annual summary on fugitive dust control activities performed on the Granger Road and the plant service road. The report shall include the date and amount of chemical dust suppressant or water applied.

(b) The reports shall be based on the fugitive emissions control records kept in accordance with condition F20 of this permit.

(c) The annual reports shall be submitted in accordance with condition G4 of this permit.

(F29) PARTICULATE EMISSION AND COMPLIANCE ASSURANCE MONITORING REPORTS [WAQSR Ch 6, Sec 3(h)(i)(C)(III); Ch 7, Sec 3(i)(ii)]

(a) The permittee shall report to the Division by January 31 and July 31 each year the results of CAM required under condition F13 of this permit, and shall include the following:

(i) Summary information on the number, duration, and cause of excursions, as applicable, and the corrective actions taken;

(ii) Summary information on the number, duration, and cause for monitor downtime incidents; and

(iii) A description of the action taken to implement a QIP (if required) during the reporting period as specified in Chapter 7, Section 3 (h). Upon completion of a QIP, the permittee shall include in the next summary report documentation that the implementation of the plan has reduced the likelihood of similar excursions.

(iv) If no excursions, corrective actions, or monitor downtime incidents occurred during the reporting period, this shall be stated in the report.

(b) All instances of deviations from the conditions of this permit must be clearly identified in each report.

(c) The semiannual reports shall be submitted in accordance with condition G4 of this permit.

(F30) TESTING, NO_X AND SO_2 EMISSIONS MONITORING REPORTS [WAQSR Ch 6, Sec 3 (h)(i)(C)(III)]

(a) For the SO_2 and NO_X emissions from the #1 and #2 coal-fired boilers (units 14 & 15), the permittee shall submit reports to the Division in accordance with condition P60-D4 of this permit.

(b) For any emissions testing required under condition F9, F10 and F14(b) of this permit, the permittee shall provide the Division 15 days prior notice of the test date.

(c) The permittee shall submit a test report for the testing required under conditions F9 and F14(b) and any additional testing required under condition F10 of this permit within 45 days of completing the testing.

(d) All instances of deviations from the conditions of this permit must be clearly identified in each report.

(e) The reports shall include the information specified under condition F22 of this permit, and shall be submitted in accordance with condition G4 of this permit.

(F31) OPERATIONAL REPORTS [WAQSR Ch 6, Sec 3(h)(i)(C)(III)]

(a) The following shall be reported to the Division by January 31 and July 31 each year:

(i) Whether the permittee adhered to operational plan for CO minimization for the calciner burners. If the permittee adhered to the operational plan for CO minimization for the calciner burners, this too shall be stated in the report.

(ii) The calendar year-to-date hours of operations for units 22, 23 & 27.

(b) All instances of deviations from the conditions of this permit must be clearly identified in each report.

(c) The reports shall be submitted in accordance with condition G4 of this permit.

(F32) PRODUCTION RATE, PROCESS RATE, AND STOCKPILE SIZE REPORTS
[WAQSR Ch 6, Sec 3(h)(i)(C)(III); Ch 6, Sec 2 Permit OP-222]

(a) The following shall be reported to the Division within 60 days of the end of each calendar year:
   (i) The annual soda ash production and trona throughput determined for the previous calendar year.
   (ii) Any process rates of the #1 and #2 ore calciners (units 04 & 05) and the plant dryers (units 07, 08 & 24) which exceed the maximum process rates described in condition F8 of this permit.
   (iii) The maximum size and the annual throughput of both the active and reserve trona ore stockpiles during the previous calendar year.

(b) All instances of deviations from the conditions of this permit must be clearly identified in each report.

(c) The reports shall be submitted in accordance with condition G4 of this permit.

(F33) QUARTERLY AMBIENT PARTICULATE MONITORING REPORTS [WAQSR Ch 6, Sec 3(h)(i)(C)(III)]
The ambient particulate data retained in accordance with condition F25 of this permit shall be submitted to the Division in an acceptable format within 60 days of the end of each calendar quarter. The reports shall be submitted to the Division in accordance with condition G4 of this permit.

(F34) REPORTING EXCESS EMISSIONS & DEVIATIONS FROM PERMIT REQUIREMENTS
[WAQSR Ch 6, Sec 3(h)(i)(C)(III)]

(a) General reporting requirements are described under the General Conditions of this permit. The Division reserves the right to require reports as provided under condition G1 of this permit.

(b) Emissions which exceed the limits specified in this permit and that are not reported to the Division under a different condition of this permit, shall be reported annually with the emission inventory unless specifically superseded by condition G17, condition G19, or other condition(s) of this permit. The probable cause of such exceedance, the duration of the exceedance, the magnitude of the exceedance, and any corrective actions or preventative measures taken shall be included in this annual report. For sources and pollutants which are not continuously monitored, if at any time emissions exceed the limits specified in this permit by 100 percent, or if a single episode of emission limit exceedance spans a period of 24 hours or more, such exceedance shall be reported to the Division within one working day of the exceedance. (Excess emissions due to an emergency shall be reported as specified in condition G17. Excess emissions due to unavoidable equipment malfunction shall be reported as specified in condition G19.)

(c) Any other deviation from the conditions of this permit shall be reported to the Division in writing within 30 days of the deviation or discovery of the deviation.

WAQSR CHAPTER 5, SECTION 2 NEW SOURCE PERFORMANCE STANDARDS (NSPS) AND 40 CFR PART 60, SUBPART D REQUIREMENTS

(Subpart D is provided in Appendix E)

(P60-D1) EMISSION STANDARDS [40 CFR Part 60, Subpart D]

The #1 and #2 coal-fired boilers (units 14 & 15) shall comply with all applicable requirements of 40 CFR Part 60, Subpart D and WAQSR Ch 5, Sec 2.

- (a) The permittee shall meet all standards for particulate emissions as specified in §60.42(a)(1).
- (b) The permittee shall meet all standards for opacity as specified in §60.42(a)(2). Compliance with condition F3(a) of this permit is considered compliance with Subpart D.
- (c) The permittee shall meet all standards for SO_2 emissions as specified in §60.43(a)(2). Compliance with condition S4 of this permit is considered compliance with Subpart D.
- (d) The permittee shall meet all standards for NO_X emissions as specified in §60.44(a)(3).

(P60-D2) EMISSION MONITORING [WAQSR Ch 5, Sec 2(j)(v); and 40 CFR Part 60, Subpart D]

- (a) For emissions from the #1 and #2 coal-fired boilers (units 14 & 15), the permittee shall maintain and operate continuous monitoring systems for opacity, SO_2 emissions, NO_x emissions, and either O_2 or CO_2 emissions as described in §60.45 of the subpart.
- (b) Except for system breakdown, repairs, calibration checks, and zero and span adjustments required under WAQSR Chapter 5, Section 2(j)(iv), all continuous monitoring systems shall be in continuous operation and shall meet the minimum frequency of operation requirements as follows:
  - (i) All continuous monitoring systems referenced by WAQSR Chapter 5, Section 2 (j)(iii)(A) and (B) for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive ten-second period and one cycle of data recording for each successive six-minute period.
  - (ii) All continuous monitoring systems referenced by WAQSR Chapter 5, Section 2 (j)(iii)(A) and (B) for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15 minute period.
  - (iii) The continuous monitoring systems need not be operated when the emission source is not in operation and no pollutants are being emitted from the stack.

(P60-D3) RECORDKEEPING [WAQSR Ch 5, Sec 2 (g)(ii) and (g)(v)]

- (a) The permittee shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the #1 and #2 coal-fired boilers (units 14 & 15); any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.
- (b) The permittee shall maintain records of all measurements, including continuous monitoring systems, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; reports; and other information required by the P60 conditions of this permit in a permanent form suitable for inspection.
- (c) The records shall be retained on-site at the facility for a period of at least five years from the date of the occurrence or from the date the record is generated.

(P60-D4) EXCESS EMISSIONS AND MONITORING SYSTEM PERFORMANCE REPORTS [WAQSR Ch 5, Sec 2 (g)(iii) and (iv); and 40 CFR Part 60, Subpart D]

- (a) The permittee shall submit an excess emissions and monitoring systems performance report (excess emissions are defined in paragraph (b) of this condition) and/or a summary report form (see paragraph (a)(v) of this condition) to the Administrator quarterly. A separate report shall be submitted for each pollutant. All reports shall be postmarked by the 30th day following the end of each calendar quarter, shall be in a format approved by the Division, and shall include the following information:
  - (i) The magnitude of excess emissions computed in accordance with WAQSR Chapter 5, Section 2(j)(viii), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The operating time for each boiler (units 14 and 15) during the reporting period.

(ii) Specific identification of each period of excess emissions that occurs during start-ups, shutdowns, or malfunctions of the coal fired boilers (units 14 and 15). The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(iii) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span check and the nature of the system repairs or adjustments.

(iv) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

(v) One summary report form for each pollutant monitored at the #1 and #2 Coal-Fired Boilers in a format approved by the Division.

(A) If the total duration of excess emissions for the reporting period is less than one percent of the total operating time for the reporting period and continuous monitoring system downtime for the reporting period is less than five percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in paragraph (a) of this condition need not be submitted unless requested by the Administrator.

(B) If the total duration of excess emissions for the reporting period is one percent or greater of the total operating time for the reporting period or the total continuous monitoring system downtime for the reporting period is five percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in paragraph (a) of this condition shall both be submitted.

(b) For the purpose of reporting under this condition, excess emissions are defined as:

(i) For opacity, excess emissions are defined under §60.45 (g)(1).

(ii) For SO_2, excess emissions are defined under §60.45 (g)(2). The reporting of exceedances of the state only SO_2 emission limit as described in conditions S4 and S10 is considered compliance with the NSPS requirement.

(iii) For NO_X, excess emissions are defined under §60.45 (g)(3).

(iv) Notwithstanding the frequency of reporting requirements specified in paragraph (a) of this condition, a permittee who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual as described in WAQSR Chapter 5, Section 2(g)(iv). Any reduction in reporting frequency requires a significant modification to this operating permit pursuant to WAQSR Chapter 6, Section 3(d)(vi)(C).

(c) The reports shall be submitted to the Division in accordance with condition G4 of this permit.

(P60-D5) GOOD AIR POLLUTION CONTROL PRACTICE [WAQSR Ch 5, Sec 2(i)(iv)]

At all times, including periods of startup, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate the #1 and #2 coal fired boilers (units 14 &15), including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions.

WAQSR CHAPTER 5, SECTION 3
NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAPS)
40 CFR PART 63, SUBPART DDDDD REQUIREMENTS

(Subpart DDDDD is provided in Appendix F)

(P63-DDDDD1) EMISSION STANDARDS [40 CFR Part 63, Subpart DDDDD and WAQSR Ch 5, Sec 3]
The permittee shall meet all requirements of 40 CFR Part 63, Subpart DDDDD and WAQSR Chapter 5, Section 3 as they apply to each affected source as indicated in §63.7490. The affected source is the collection of industrial, commercial and institutional boilers and process heaters as defined in §§63.7490 and 63.7575. The #1 and #2 coal fired boilers (units 14 &15) shall meet the applicable emission limits, work practice standards, and operating limits described in §§63.7500, 63.7507, and 63.7522.

(P63-DDDDD2) TESTING, FUEL ANALYSIS, AND INITIAL COMPLIANCE DEMONSTRATION [40 CFR Part 63, Subpart DDDDD §§63.7505 through 63.7530 and WAQSR Ch 5, Sec 3(h) and (i)]

(a) The permittee shall demonstrate initial compliance with the requirements in condition P63-DDDDD1 using the test methods and procedures in §§63.7507, 63.7510, 63.7530, 63.7520, 63.7521, and 63.7522, as applicable.
(b) Subsequent performance testing and fuel analysis shall meet the requirements in §§63.7515, 63.7520, and 63.7521.
(c) The permittee may demonstrate compliance with any applicable emission limit using fuel analysis if the emission rate calculated according to §63.7530(d) is less than the applicable emission limit.
(d) Performance testing and fuel analysis shall meet all requirements for documentation, quality assurance, and other criteria in Subpart DDDDD and WAQSR Chapter 5, Section 3(h)(vii) and Section 3(i) except as specified in Table 10 to Subpart DDDDD.

(P63-DDDDD3) MONITORING REQUIREMENTS [40 CFR Part 63, Subpart DDDDD §§63.7505, 63.7525, and §§63.7535 through 63.7541; and WAQSR Ch 5, Sec 3(j)]

(a) If the permittee demonstrates compliance with any applicable emission limit through performance testing, the permittee must develop a site-specific monitoring plan according to the requirements in §63.7505(d).
(b) Any continuous opacity monitors (COMs) and continuous monitoring systems (CMSs) required by Subpart DDDDD shall be installed, operational, and the data verified either prior to or in conjunction with conducting performance tests under condition P63-DDDDD2. Verification of operational status shall, at a minimum, include completion of the manufacturer's written specifications or recommendations for installation, operation, and calibration of the system.
(c) Monitoring data from COMs and CMSs shall be reduced in accordance with Chapter 5, Section 3(j)(vii)(A) through (D) and §63.7535(c).
(d) The permittee shall meet all other applicable monitoring requirements as specified in §§63.7505, 63.7525, and 63.7535 through 63.7541 and WAQSR Chapter 5, Section 3(j), except as specified in Table 10 to Subpart DDDDD.

(P63-DDDDD4) OPERATION & MAINTENANCE REQUIREMENTS [40 CFR Part 63, Subpart DDDDD §§63.7505 and 63.7535; and WAQSR Ch 5, Sec 3(h)(iv)(A)(I) and (II), Sec 3(i)(iii), and Sec 3(j)]

(a) At all times, including periods of startup, shutdown, and malfunction, the permittee shall operate and maintain affected boilers and process heaters, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions at least to the levels required by Subpart DDDDD.
(b) Malfunctions shall be corrected as soon as practicable after their occurrence in accordance with the startup, shutdown, and malfunction plan required in condition P63-DDDDD5 of this permit.
(c) The permittee must keep the necessary parts for routine repairs of the COM and CMS equipment readily available.
(d) Except for monitor malfunctions, associated repairs, and required quality assurance or control activities, (including, as applicable, calibration checks and required zero and span adjustments), the permittee must monitor continuously (or collect data at all required intervals) at all times that the affected source is operating.

(e) All COMs required by Subpart DDDDD shall complete a minimum of one cycle of sampling and analyzing for each successive ten-second period and one cycle of data recording for each successive six-minute period.

(f) The permittee shall develop and implement a COM and CMS quality control program.

  (i) The permittee shall develop, and upon request submit to the Administrator in accordance with condition G4, a site-specific performance evaluation test plan for approval upon request. The plan shall be developed according to the procedures in WAQSR Chapter 5, Section 3(i)(iii)(B) and 3(j)(v).

  (ii) The performance evaluation test shall be conducted as described in Chapter 5, Section 3(j)(v)(D).

  (iii) Each quality control program shall include, at a minimum, a written protocol that describes procedures for each of the following operations:

    (A) Initial and any subsequent calibration of the CMS/COM;
    (B) Determination and adjustment of the calibration drift of the CMS/COM;
    (C) Preventive maintenance of the CMS/COM, including spare parts inventory;
    (D) Data recording, calculations, and reporting;
    (E) Accuracy audit procedures, including sampling and analysis methods; and
    (F) Program for corrective action for a malfunctioning CMS/COM.

  (iv) The permittee shall keep these written procedures on record to be made available for inspection, upon request, by the Administrator for the life of the #1 and #2 coal-fired boilers (units 14 & 15) or until these units are no longer subject to Chapter 5, Section 3. In addition, if the quality control program is revised, the permittee shall keep previous (i.e., superseded) versions on record, to be made available for inspection, upon request, by the Administrator, for a period of 5 years after each revision to the plan.

(g) Additional COM and CMS requirements are specified in Chapter 5, Section 3(j)(iii) and (iv), except as specified in Table 10 to Subpart DDDDD.

(P63-DDDDD5) STARTUP, SHUTDOWN, & MALFUNCTION PLAN [40 CFR Part 63, Subpart DDDDD §§63.7505 and WAQSR Ch 5, Sec 3(h)(iv)(C)]

(a) If the permittee has an applicable emission limit or work practice standard under Subpart DDDDD, then the permittee shall maintain and implement a written startup, shutdown, and malfunction plan (SSMP) that describes, in detail, procedures for operating and maintaining the source during periods of startup, shutdown, and malfunction, and a program of corrective action for malfunctioning process and air pollution control equipment used to comply with Subpart DDDDD. The plan shall identify all routine or otherwise predictable COM and CMS malfunctions.

(b) During periods of startup, shutdown, and malfunction, the permittee shall operate and maintain affected boilers and process heaters (including associated air pollution control equipment) in accordance with the procedures specified in the SSMP developed under paragraph (a) of this condition.

(c) When actions taken by the permittee during a startup, shutdown, or malfunction (including actions taken to correct a malfunction) are consistent with the procedures specified in the SSMP, the permittee shall keep records for that event that demonstrate the procedures specified in the plan were followed. These records may take the form of a "checklist," or other effective form of recordkeeping, that confirms conformance with the SSMP for that event.

(d) If an action taken by the permittee during a startup, shutdown, or malfunction (including an action taken to correct a malfunction) is not consistent with the procedures specified in the SSMP, the permittee shall record the actions taken for that event.

(e) The permittee shall keep the written SSMP on record to be made available for inspection, upon request, by the Administrator for the life of the #1 and #2 coal-fired boilers (units 14 & 15) or until these units are no longer subject to the provisions of Chapter 5, Section 3. In addition, if the SSMP is revised, the permittee shall keep previous (i.e., superseded) versions of the SSMP on record, to be made available for inspection, upon request, by the Administrator, for a period of 5 years after each revision to the plan.

(f) To satisfy the requirements of this condition to develop a SSMP, the permittee may use their standard operating procedures (SOP) manual, or an Occupational Safety and Health Administration (OSHA) or other plan, provided the alternative plans meet all the requirements of Chapter 5, Section 3 and are made available for inspection when requested by the Administrator.

(g) If the SSMP fails to address or inadequately addresses an event that meets the characteristics of a malfunction but was not included in the SSMP at the time the permittee developed the plan, the permittee shall revise the SSMP within 45 days after the event to include detailed procedures for operating and maintaining the source during similar malfunction events and a program of corrective action for similar malfunctions of process or air pollution control equipment.

(P63-DDDDD6) GENERAL RECORDKEEPING REQUIREMENTS [40 CFR Part 63, Subpart DDDDD §§63.7555 and 63.7560; and WAQSR Ch 5, Sec 3(l)(ii) and (iii)]

(a) The permittee shall maintain files of all information (including all reports and notifications) required by Subpart DDDDD and Chapter 5, Section 3 recorded in a form suitable and readily available for expeditious inspection and review. The files shall be retained for at least 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. At a minimum, the most recent 2 years of data shall be retained on site at the facility. The remaining 3 years of data may be retained off site. Such files may be maintained on microfilm, on a computer, on computer floppy disks, on magnetic tape disks, or on microfiche.

(b) The permittee shall maintain relevant records for affected boilers and process heaters of the following:
- (i) The occurrence and duration of each startup, shutdown, or malfunction of operation (i.e., process equipment);
- (ii) The occurrence and duration of each malfunction of the air pollution control equipment;
- (iii) All maintenance performed on the air pollution control equipment;
- (iv) Actions taken during periods of startup, shutdown, and malfunction (including corrective actions to restore malfunctioning process and air pollution control equipment to its normal or usual manner of operation) when such actions are different from the procedures specified in the SSMP;
- (v) All information necessary to demonstrate conformance with the SSMP when all actions taken during periods of startup, shutdown, and malfunction (including corrective actions to restore malfunctioning process and air pollution control equipment to its normal or usual manner of operation) are consistent with the procedures specified in such plan. (The information needed to demonstrate conformance with the SSMP may be recorded using a "checklist," or some other effective form of recordkeeping, to minimize the recordkeeping burden for conforming events);
- (vi) Each period during which a COM or CMS is malfunctioning or inoperable (including out-of-control periods).
- (vii) All required measurements needed to demonstrate compliance with Subpart DDDDD;
- (viii) All results of performance tests, fuel analyses, other compliance demonstrations, COM or CMS performance evaluations, and opacity and visible emission observations;
- (ix) All COM and CMS calibration checks;
- (x) All adjustments and maintenance performed on COMs and CMSs;
- (xi) All measurements as may be necessary to determine the conditions of performance tests and performance evaluations;
- (xii) A copy of each notification and report that the permittee submitted to comply with Subpart DDDDD;
- (xiii) All records of applicability determination, including supporting analysis;
- (xiv) All other records for COMs and CMSs required by Chapter 5, Section 3(l)(iii).
- (xv) All other records required by §63.7555 and Chapter 5, Section 3, except as specified in Table 10 to Subpart DDDDD.

(P63-DDDDD7) NOTIFICATION REQUIREMENTS [40 CFR Part 63, Subpart DDDDD §63.7545 and WAQSR Ch 5, Sec 3(h), (i), (j), and (k)]

(a) The permittee shall submit notifications required under this permit condition P63-DDDDD7, Subpart DDDDD, and Chapter 5, Section 3 to the Administrator and U.S. EPA Region VIII in accordance with condition G4 of this permit.

(b) The permittee shall notify the Administrator in writing of their intention to conduct any performance test required by condition P63-DDDDD2 at least 30 calendar days before the performance test is scheduled to begin.

(c) The permittee shall notify the Administrator in writing of the date the performance evaluation required by condition P63-DDDDD4(e) is scheduled to begin, simultaneously with the notification of performance test date required by (b) above.

(d) The permittee shall, if requested, submit the site-specific performance evaluation test plan required by P63-DDDDD4(e) simultaneously with the notification required by (b) above.

(e) The permittee shall submit a report of the results of a CMS performance evaluation as follows:

(i) For any COMs required by condition P63-DDDDD3, two copies of the written report of the COM performance evaluation conducted under condition P63-DDDDD4(e) shall be submitted to the Administrator at least 15 days before any COMS performance test required under condition P63-DDDDD2.

(ii) For any CMS required by condition P63-DDDDD3, a written report of the results of the performance evaluation conducted under condition P63-DDDDD4(e) shall be submitted to the Administrator simultaneously with the performance test results required under paragraph (f) below.

(f) The permittee shall submit a Notification of Compliance Status with Subpart DDDDD upon completion of any relevant initial compliance demonstration activity, including all performance test results and fuel analyses, before the close of business on the 60th day following completion of the compliance demonstration.

(i) The Notification of Compliance Status shall contain all the information specified in §63.7545(e), as applicable.

(ii) For performance tests, the Notification of Compliance Status shall include COM data produced during the performance test, if the source tested is required to use a COM.

(g) The permittee shall submit all other notifications as required by 40 CFR Part 63, Subpart DDDDD and WAQSR Chapter 5, Section 3.

(P63-DDDDD8) REPORTING REQUIREMENTS [40 CFR Part 63, Subpart DDDDD §63.7550 and WAQSR Ch 5, Sec 3(j) and Sec 3(l)(i), (iv), and (v)]

(a) The permittee shall submit reports required under this permit condition P63-DDDDD8, §63.7550, and Chapter 5, Section 3 to the Administrator and U.S. EPA Region VIII in accordance with condition G4 of this permit.

(b) The permittee shall submit each report in Table 9 of Subpart DDDDD that applies, according to the timing requirements in §63.7550(b).

(i) Initial and semiannual compliance reports shall contain the information required by Table 9 and §63.7550(c) through (f).

(ii) If actions taken by the permittee during a startup, shutdown, or malfunction of affected boilers or process heaters (including actions taken to correct a malfunction) are consistent with the procedures specified in the source's SSMP, the permittee shall state such information in a startup, shutdown, and malfunction report. Reports shall only be required if a startup, shutdown, or malfunction occurred during the reporting period. The startup, shutdown, and malfunction report shall consist of a letter, containing the name, title, and signature of the responsible official who is certifying its accuracy, which shall be submitted to the Administrator semiannually. The startup, shutdown, and malfunction report shall be submitted simultaneously with the compliance reports.

(iii) Immediate startup, shutdown, and malfunction reports:

(A) Any time an action taken by a permittee during a startup, shutdown, or malfunction is not consistent with the procedures in the SSMP, the permittee shall make a report of the actions taken for the event by telephone call or facsimile (FAX) transmission within 2 working days after starting actions inconsistent with the plan. The immediate report shall be followed by a letter, delivered or postmarked within 7 working days after the end of the event, that contains the name, title, and signature of the responsible official who is certifying its accuracy, explaining the circumstances of the event, the reasons for not following the startup, shutdown, and malfunction plan, and whether any excess emissions and/or parameter monitoring exceedances are believed to have occurred.

(B) For those malfunctions and or other events that affect a CMS/COM and are not addressed by the SSMP, the permittee shall send a follow-up report within 2 weeks after commencing actions inconsistent with the plan that either certifies that corrections have been made or includes a corrective action plan and schedule. The permittee shall provide proof that repair parts have been ordered or any other records that would indicate that the delay in making repairs is beyond their control.

(c) The permittee shall submit all other reports as required by §63.7550 and Chapter 5, Section 3.

WAQSR CHAPTER 7, SECTION 3
COMPLIANCE ASSURANCE MONITORING (CAM) REQUIREMENTS

(CAM-1) COMPLIANCE ASSURANCE MONITORING REQUIREMENTS [WAQSR Ch 7, Sec 3(b) and (c)]
The permittee shall follow the CAM plan attached as Appendix C of this permit and meet all CAM requirements of WAQSR Chapter 7, Section 3 as they apply to the Baghouse, Scrubber and ESP controlled units (01, 03, 09, 10, 11, 12, 13, 16, 18, 07, 08, 24 04, 05, 14 & 15). Compliance with the source specific monitoring, recordkeeping, and reporting requirements of this permit meets the monitoring, recordkeeping, and reporting requirements of WAQSR Chapter 7, Section 3, except for additional requirements specified under conditions CAM-2 through CAM-4.

(CAM-2) OPERATION OF APPROVED MONITORING [WAQSR Ch 7, Sec 3 (g)]

(a) At all times, the permittee shall maintain the monitoring under this section, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.

(b) Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities, the permittee shall conduct all monitoring in continuous operation (or at all required intervals) at all times that the pollutant specific emissions unit is operating.

(c) Upon detecting an excursion, the permittee shall restore operation of the pollutant-specific emission unit to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices. The response shall include minimizing the period of any start-up, shutdown or malfunction and taking any corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion.

(d) If the permittee identifies a failure to achieve compliance with an emission limit for which the monitoring did not provide an indication of an excursion while providing valid data, or the results of compliance or performance testing documents a need to modify the existing indicator ranges, the permittee shall promptly notify the Division and, if necessary, submit a proposed modification to this permit to address the necessary monitoring changes.

(CAM-3) QUALITY IMPROVEMENT PLAN (QIP) REQUIREMENTS [WAQSR Ch 7, Sec 3 (h)]

(a) If the Division or the EPA Administrator determines, based on available information, that the permittee has used unacceptable procedures in response to an excursion or exceedance, the permittee may be required to develop and implement a Quality Improvement Plan (QIP).

(b) If required, the permittee shall maintain a written QIP and have it available for inspection.

(c) The plan shall include procedures for conducting one or more of the following:
   (i) Improved preventative maintenance practices.
   (ii) Process operation changes.
   (iii) Appropriate improvements to control methods.
   (iv) Other steps appropriate to correct control.
   (v) More frequent or improved monitoring (in conjunction with (i) - (iv) above).

(d) If a QIP is required, the permittee shall develop and implement a QIP as expeditiously as practicable and shall notify the Division if the period for completing the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.

(e) Following implementation of a QIP, upon any subsequent determination under paragraph (a) above, the Division may require the permittee to make reasonable changes to the QIP if the QIP failed to address the cause of control device problems, or failed to provide adequate procedures for correcting control device problems as expeditiously as practicable.

(f) Implementation of a QIP shall not excuse the permittee from compliance with any existing emission limit(s) or any existing monitoring, testing, reporting, or recordkeeping requirements that may be applicable to the facility.

(CAM-4) SAVINGS PROVISIONS [WAQSR Ch 7, Sec 3 (j)]
Nothing in the CAM regulations shall excuse the permittee from compliance with any existing emission limit or standard, or any existing monitoring, testing, reporting, or recordkeeping requirement that may be applicable to the facility.

COMPLIANCE CERTIFICATION AND SCHEDULE

Compliance Certification [WAQSR Ch 6, Sec 3 (h)(iii)(E)]

(C1) (a) The permittee shall submit by January 31 each year a certification addressing compliance with the requirements of this permit. The certification shall be submitted as a stand-alone document separate from any monitoring reports required under this permit.

(b) (i) For production rate, process rate and stockpile limits, the permittee shall assess compliance with conditions F1 & F8 of this permit by conducting the monitoring required by condition F16 and reviewing the records maintained in accordance with condition F24 of this permit.

(ii) For the sulfur dioxide emission inventory, the permittee shall assess compliance with condition F2 of this permit by reviewing the records maintained in accordance with condition F18 of this permit.

(iii) For visible emissions, the permittee shall assess compliance with condition F3 of this permit by conducting the monitoring required by condition F11 and reviewing the records maintained in accordance with condition F19 of this permit.

(iv) For fugitive emissions, the permittee shall assess compliance with condition F4 of this permit by conducting the monitoring required by condition F12 and reviewing the records maintained in accordance with condition F20 of this permit.

(v) For particulate emissions, the permittee shall assess compliance with condition F5 of this permit by conducting the CAM monitoring required by condition F13 of this permit.

(vi) For NO_X emissions from the #1 and #2 coal-fired boilers, and the #1 and #2 Ore Calciners, the permittee shall assess compliance with condition F6 of this permit by conducting the monitoring required by condition F14 and reviewing the records maintained in accordance with condition F22 of this permit.

(vii) For the operational limitations, the permittee shall assess compliance with condition F7 of this permit by reviewing the records maintained in accordance with condition F23 of this permit.

(viii) For the ambient particulate monitoring, the permittee shall assess compliance with condition F17 of this permit by reviewing the records maintained in accordance with condition F25 of this permit.

(ix) The permittee shall assess compliance with condition P60-D1 of this permit by conducting the monitoring required by condition P60-D2 of this permit.

(x) The permittee shall assess compliance with conditions P63-DDDDD1 and P63-DDDDD2 of this permit by conducting the monitoring required by condition P63-DDDDD3 of this permit.

(c) The compliance certification shall include:

(i) The permit condition or applicable requirement that is the basis of the certification;

(ii) The current compliance status;

(iii) Whether compliance was continuous or intermittent; and

(iv) The methods used for determining compliance.

(d) For any permit conditions or applicable requirements for which the source is not in compliance, the permittee shall submit with the compliance certification a proposed compliance plan and schedule for Division approval.

(e) The compliance certification shall be submitted to the Division in accordance with condition G4 of this permit and to the Assistant Regional Administrator, Office of Enforcement, Compliance, and Environmental Justice (8ENF-T), U.S. EPA - Region VIII, 1595 Wynkoop Street, Denver, CO 80202-1129.

(f) Determinations of compliance or violations of this permit are not restricted to the monitoring requirements listed in paragraph (b) of this condition; other credible evidence may be used.

Compliance Schedule [WAQSR Ch 6, Sec 3 (h)(iii)(C) and (D)]

(C2) The permittee shall continue to comply with the applicable requirements with which the permittee has certified that it is already in compliance.

(C3) The permittee shall comply in a timely manner with applicable requirements that become effective during the term of this permit.

GENERAL PERMIT CONDITIONS

Powers of the Administrator: [W.S. 35-11-110]

(G1) (a) The Administrator may require the owner or operator of any point source to complete plans and specifications for any application for a permit required by the Wyoming Environmental Quality Act or regulations made pursuant thereto and require the submission of such reports regarding actual or potential violations of the Wyoming Environmental Quality Act or regulations thereunder.

(b) The Administrator may require the owner or operator of any point source to establish and maintain records; make reports; install, use and maintain monitoring equipment or methods; sample emissions, or provide such other information as may be reasonably required and specified.

Permit Renewal and Expiration: [WAQSR Ch 6, Sec 3(c)(i)(C), (d)(ii), (d)(iv)(B), and (h)(i)(B)] [W.S. 35-11-206(f)]

(G2) This permit is issued for a fixed term of five years. Permit expiration terminates the permittee's right to operate unless a timely and complete renewal application is submitted at least six months prior to the date of permit expiration. If the permittee submits a timely and complete application for renewal, the permittee's failure to have an operating permit is not a violation of WAQSR Chapter 6, Section 3 until the Division takes final action on the renewal application. This protection shall cease to apply after a completeness determination if the applicant fails to submit by the deadline specified in writing by the Division any additional information identified as being needed to process the application.

Duty to Supplement: [WAQSR Ch 6, Sec 3(c)(iii)]

(G3) The permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, shall promptly submit such supplementary facts or corrected information. The permittee shall also provide additional information as necessary to address any requirements that become applicable to the facility after this permit is issued.

Submissions: [WAQSR Ch 6, Sec 3(c)(iv)] [W.S. 35-11-206(c)]

(G4) Any document submitted shall be certified as being true, accurate, and complete by a responsible official.

(a) Submissions to the Division.

(i) Any submissions to the Division including reports, certifications, and emission inventories required under this permit shall be submitted as separate, stand-alone documents and shall be sent to:

Administrator, Air Quality Division
122 West 25th Street
Cheyenne, Wyoming 82002

(ii) A copy of each submission to the Administrator under paragraph (a)(i) of this condition shall be sent to the DEQ Air Quality Contact listed on page 3 of this permit.

(b) Submissions to EPA.

(i) Each certification required under condition C1 of this permit shall also be sent to:

Assistant Regional Administrator
Office of Enforcement, Compliance, and Environmental Justice (8ENF-T)
U.S. EPA - Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129

(ii) All other required submissions to EPA shall be sent to:

Office of Partnerships and Regulatory Assistance
Air and Radiation Program (8P-AR)
U.S. EPA - Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129

Changes for Which No Permit Revision Is Required: [WAQSR Ch 6, Sec 3(d)(iii)]

(G5) The permittee may change operations without a permit revision provided that:
- (a) The change is not a modification under any provision of title I of the Clean Air Act;
- (b) The change has met the requirements of Chapter 6, Section 2 of the WAQSR and is not a modification under Chapter 5, Section 2 or Chapter 6, Section 4 of the WAQSR and the changes do not exceed the emissions allowed under the permit (whether expressed therein as a rate of emissions or in terms of total emissions); and
- (c) The permittee provides EPA and the Division with written notification at least 14 days in advance of the proposed change. The permittee, EPA, and the Division shall attach such notice to their copy of the relevant permit. For each such change, the written notification required shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield, if one exists for this permit, shall not apply to any such change made.

Transfer of Ownership or Operation: [WAQSR Ch 6, Sec 3(d)(v)(A)(IV)]

(G6) A change in ownership or operational control of this facility is treated as an administrative permit amendment if no other change in this permit is necessary and provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee has been submitted to the Division.

Reopening for Cause: [WAQSR Ch 6, Sec 3(d)(vii)] [W.S. 35-11-206(f)(ii) and (iv)]

(G7) The Division will reopen and revise this permit as necessary to remedy deficiencies in the following circumstances:
- (a) Additional applicable requirements under the Clean Air Act or the WAQSR that become applicable to this source if the remaining permit term is three or more years. Such reopening shall be completed not later than 18 months after promulgation of the applicable requirement. No reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions have been extended.
- (b) Additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program. Upon approval by EPA, excess emissions offset plans shall be deemed to be incorporated into the permit.
- (c) The Division or EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit.
- (d) The Division or EPA determines that the permit must be revised or revoked to assure compliance with applicable requirements.

Annual Fee Payment: [WAQSR Ch 6, Sec 3(f)(i), (ii), and (vi)] [W.S. 35-11-211]

(G8) The permittee shall, as a condition of continued operations, submit an annual fee to the Division as established in Chapter 6, Section 3 (f) of the WAQSR. The Division shall give written notice of the amount of fee to be assessed and the basis for such fee assessment annually. The assessed fee is due on receipt of the notice unless the fee assessment is appealed pursuant to W.S. 35-11-211(d). If any part of the fee assessment is not appealed it shall be paid to the Division on receipt of the written notice. Any remaining fee which may be due after completion of the appeal is immediately due and payable upon issuance of the Council's decision. Failure to pay fees owed the Division is a violation of Chapter 6, Section 3 (f) and W.S. 35-11-203 and may be cause for the revocation of this permit.

Annual Emissions Inventories: [WAQSR Ch 6, Sec 3(f)(v)(G)]

(G9) The permittee shall submit an annual emission inventory for this facility to the Division for fee assessment and compliance determinations within 60 days following the end of the calendar year. The emissions inventory shall be in a format specified by the Division.

Severability Clause: [WAQSR Ch 6, Sec 3(h)(i)(E)]

(G10) The provisions of this permit are severable, and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.

Compliance: [WAQSR Ch 6, Sec 3(h)(i)(F)(I) and (II)] [W.S. 35-11-203(b)]

(G11) The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the Clean Air Act, Article 2 of the Wyoming Environmental Quality Act, and the WAQSR and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

Permit Actions: [WAQSR Ch 6, Sec 3(h)(i)(F)(III)] [W.S. 35-11-206(f)]

(G12) This permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

Property Rights: [WAQSR Ch 6, Sec 3(h)(i)(F)(IV)]

(G13) This permit does not convey any property rights of any sort, or any exclusive privilege.

Duty to Provide Information: [WAQSR Ch 6, Sec 3(h)(i)(F)(V)]

(G14) The permittee shall furnish to the Division, within a reasonable time, any information that the Division may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Division copies of records required to be kept by the permit, including information claimed and shown to be confidential under W.S. 35-11-1101 (a) of the Wyoming Environmental Quality Act. Upon request by the Division, the permittee shall also furnish confidential information directly to EPA along with a claim of confidentiality.

Emissions Trading: [WAQSR Ch 6, Sec 3(h)(i)(H)]

(G15) There are no emissions trading provisions in this permit.

Inspection and Entry: [WAQSR Ch 6, Sec 3(h)(iii)(B)] [W.S. 35-11-206(c)]

(G16) Authorized representatives of the Division, upon presentation of credentials and other documents as may be required by law, shall be given permission to:
- (a) Enter upon the permittee's premises where a source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;
- (b) Have access to and copy at reasonable times any records that must be kept under the conditions of this permit;
- (c) Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit;
- (d) Sample or monitor any substances or parameters at any location, during operating hours, for the purpose of assuring compliance with this permit or applicable requirements.

Excess Emissions Due to an Emergency: [WAQSR Ch 6, Sec 3(l)]

(G17) The permittee may seek to establish that noncompliance with a technology-based emission limitation under this permit was due to an emergency, as defined in Ch 6, Sec 3(l)(i) of the WAQSR. To do so, the permittee shall demonstrate the affirmative defense of emergency through properly signed, contemporaneous operating logs, or other relevant evidence that:
- (a) An emergency occurred and that the permittee can identify the cause(s) of the emergency;
- (b) The permitted facility was, at the time, being properly operated;
- (c) During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards, or other requirements in this permit;

(d) The permittee submitted notice of the emergency to the Division within one working day of the time when emission limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

Diluting and Concealing Emissions: [WAQSR Ch 1, Sec 4]

(G18) No person shall cause or permit the installation or use of any device, contrivance, or operational schedule which, without resulting in reduction of the total amount of air contaminant released to the atmosphere, shall dilute or conceal an emission from a source. This condition shall not apply to the control of odors.

Unavoidable Equipment Malfunction: [WAQSR Ch 1, Sec 5]

(G19) (a) Any source believing that any emissions in excess of established regulation limits or standards resulted from an unavoidable equipment malfunction, shall notify the Division within 24 hours of the incident via telephone, electronic mail, fax, or other similar method. A detailed description of the circumstances of the incident as described in paragraph 5(a)(i)(A) Chapter 1, including a corrective program directed at preventing future such incidents, must be submitted within 14 days of the onset of the incident. The Administrator may extend this 14-day time period for cause.

(b) The burden of proof is on the owner or operator of the source to provide sufficient information to demonstrate that an unavoidable equipment malfunction occurred.

Fugitive Dust: [WAQSR Ch 3, Sec 2(f)]

(G20) The permittee shall minimize fugitive dust in compliance with standards in Ch 3, Sec 2(f) of WAQSR for construction/demolition activities, handling and transportation of materials, and agricultural practices.

Carbon Monoxide: [WAQSR Ch 3, Sec 5]

(G21) The emission of carbon monoxide in stack gases from any stationary source shall be limited as may be necessary to prevent ambient standards from being exceeded.

Asbestos: [WAQSR Ch 3, Sec 8]

(G22) The permittee shall comply with emission standards for asbestos during abatement, demolition, renovation, manufacturing, spraying, and fabricating activities.

(a) No owner or operator shall build, erect, install, or use any article, machine, equipment, process, or method, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous dilutants to achieve compliance with a visible emissions standard, and the piecemeal carrying out of an operation to avoid coverage by a standard that applies only to operations larger than a specified size.

(b) All owners and operators conducting an asbestos abatement project, including an abatement project on a residential building, shall be responsible for complying with Federal requirements and State standards for packaging, transportation, and delivery to an approved waste disposal facility as provided in paragraph (m) of Ch 3, Sec 8.

(c) The permittee shall follow State and Federal standards for any demolition and renovation activities conducted at this facility, including:

(i) A thorough inspection of the affected facility or part of the facility where the demolition or renovation activity will occur shall be conducted to determine the presence of asbestos, including Category I and Category II non-friable asbestos containing material. The results of the inspection will determine which notification and asbestos abatement procedures are applicable to the activity.

(ii) The owner or operator shall follow the appropriate notification requirements of Ch 3, Sec 8(i)(ii).

(iii) The owner or operator shall follow the appropriate procedures for asbestos emissions control, as specified in Ch 3, Sec 8(i)(iii).

(d) No owner or operator of a facility may install or reinstall on a facility component any insulating materials that contain commercial asbestos if the materials are either molded and friable or wet-applied and friable after drying. The provisions of this paragraph do not apply to spray-applied insulating materials regulated under paragraph (j) of Ch 3, Sec 8.

(e) The permittee shall comply with all other requirements of WAQSR Ch 3, Sec 8.

Open Burning Restrictions: [WAQSR Ch 10, Sec 2]

(G23) The permittee conducting an open burn shall comply with all rules and regulations of the Wyoming Department of Environmental Quality, Division of Air Quality, and with the Wyoming Environmental Quality Act.

(a) No person shall burn prohibited materials using an open burning method, except as may be authorized by permit. ***"Prohibited materials"*** means substances including, but not limited to; natural or synthetic rubber products, including tires; waste petroleum products, such as oil or used oil filters; insulated wire; plastic products, including polyvinyl chloride ("PVC") pipe, tubing and connectors; tar, asphalt, asphalt shingles, or tar paper; railroad ties; wood, wood waste, or lumber that is painted or chemically treated; explosives or ammunition; batteries; hazardous waste products; asbestos or asbestos containing materials; or materials which cause dense smoke discharges, excluding refuse and flaring associated with oil and gas well testing, completions and well workovers.

(b) No person or organization shall conduct or cause or permit open burning for the disposal of trade wastes, for a salvage operation, for the destruction of fire hazards if so designated by a jurisdictional fire authority, or for fire fighting training, except when it can be shown by a person or organization that such open burning is absolutely necessary and in the public interest. Any person or organization intending to engage in such open burning shall file a request to do so with the Division.

Sulfur Dioxide Emission Trading and Inventory Program [WAQSR Ch 14]

(G24) Any BART (Best Available Retrofit Technology) eligible facility, or facility which has actual emissions of SO_2 greater than 100 tpy in calendar year 2000 or any subsequent year, shall comply with the applicable requirements of WAQSR Ch 14, Sections 1 through 3, with the exceptions described in sections 2(c) and 3(a).

Stratospheric Ozone Protection Requirements: [40 CFR Part 82]

(G25) The permittee shall comply with all applicable Stratospheric Ozone Protection Requirements, including but not limited to:

(a) *Standards for Appliances* [40 CFR Part 82, Subpart F]
The permittee shall comply with the standards for recycling and emission reduction pursuant to 40 CFR Part 82, Subpart F - Recycling and Emissions Reduction, except as provided for motor vehicle air conditioners (MVACs) in Subpart B:

(i) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to §82.156.

(ii) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to §82.158.

(iii) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to §82.161.

(iv) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record keeping requirements pursuant to §82.166. ("MVAC-like appliance" is defined at §82.152).

(v) Persons owning commercial or industrial process refrigeration equipment must comply with the leak repair requirements pursuant to §82.166.

(vi) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to §82.166.

(vii) The permittee shall comply with all other requirements of Subpart F.

(b) *Standards for Motor Vehicle Air Conditioners* [40 CFR Part 82, Subpart B]
If the permittee performs a service on motor (fleet) vehicles when this service involves ozone-depleting substance refrigerant in the MVAC, the permittee is subject to all the applicable requirements as specified in 40 CFR Part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners. The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant.

STATE ONLY PERMIT CONDITIONS

The conditions listed in this section are State only requirements and are not federally enforceable.

Ambient Standards:

(S1) The permittee shall operate the emission units described in this permit such that the following ambient standards are not exceeded:

POLLUTANT	STANDARD	CONDITION	WAQSR CH. 2, SEC.
PM_{10} particulate matter	50 micrograms per cubic meter	annual arithmetic mean	2 (a)
	150 micrograms per cubic meter	24-hr average concentration with not more than one exceedance per year	
$PM_{2.5}$ particulate matter	15 micrograms per cubic meter	annual arithmetic mean	2 (b)
	65 micrograms per cubic meter	98^{th} percentile 24-hour average concentration	
Nitrogen dioxide	100 micrograms per cubic meter	annual arithmetic mean	3
Sulfur oxides	60 micrograms per cubic meter	annual arithmetic mean	4
	260 micrograms per cubic meter	max 24-hr concentration with not more than one exceedance per year	
	1300 micrograms per cubic meter	max 3-hr concentration with not more than one exceedance per year	
Carbon monoxide	10 milligrams per cubic meter	max 8-hr concentration with not more than one exceedance per year	5
	40 milligrams per cubic meter	max 1-hr concentration with not more than one exceedance per year	
Ozone	0.08 parts per million	daily maximum 8-hour average	6
Hydrogen sulfide	70 micrograms per cubic meter	½ hour average not to be exceeded more than two times per year	7
	40 micrograms per cubic meter	½ hour average not to be exceeded more than two times in any five consecutive days	
Suspended sulfate	0.25 milligrams SO_3 per 100 square centimeters per day	maximum annual average	8
	0.50 milligrams SO_3 per 100 square centimeters per day	maximum 30-day value	
Lead and its compounds	1.5 micrograms per cubic meter	maximum arithmetic mean averaged over a calendar quarter	10

Hydrogen Sulfide: [WAQSR Ch 3, Sec 7]

(S2) Any exit process gas stream containing hydrogen sulfide which is discharged to the atmosphere from any source shall be vented, incinerated, flared, or otherwise disposed of in such a manner that ambient sulfur dioxide and hydrogen sulfide standards are not exceeded.

Odors: [WAQSR Ch 2, Sec 11]

(S3) (a) The ambient air standard for odors from any source shall be limited to an odor emission at the property line which is undetectable at seven dilutions with odor free air as determined by a scentometer as manufactured by the Barnebey-Cheney Company or any other instrument, device, or technique designated by the Division as producing equivalent results. The occurrence of odors shall be measured so that at least two measurements can be made within a period of one hour, these determinations being separated by at least 15 minutes.

(b) Odor producing materials shall be stored, transported, and handled in a manner that odors produced from such materials are confined and that accumulation of such materials resulting from spillage or other escape is prevented.

Sulfur Oxides: [WAQSR Ch 3, Sec 4]

Source-Specific Permit Conditions

(S4) #1 AND #2 COAL-FIRED BOILER SO_2 EMISSIONS [WAQSR Ch 3, Sec 4(c)]
SO_2 emissions from the #1 and #2 coal-fired boilers (units 14 and 15) shall be limited to 0.2 lb/MMBtu of heat input based on a fixed two-hour average.

Testing Requirements

(S5) SO_2 EMISSIONS TESTING [W.S. 35-11-110 and 40 CFR Part 60, Subpart D]
The #1 and #2 coal-fired boilers (units 14 and 15) SO_2 emissions testing requirements are described under condition F10 of this permit.

Monitoring Requirements

(S6) SO_2 EMISSIONS MONITORING [WAQSR Ch 6, Sec 3(h)(i)(C)(I) and 40 CFR Part 60, Subpart D]
The #1 and #2 coal-fired boilers (units 14 and 15) SO_2 emissions monitoring requirements are described under condition P60-D2 of this permit.

Recordkeeping Requirements

(S7) SO_2 EMISSIONS TEST RECORDS [WAQSR Ch 6, Sec 3(h)(i)(C)(II)]
Recordkeeping for any SO_2 emissions testing the Division may require for the #1 and #2 coal-fired boilers (units 14 and 15) are described under condition F22 of this permit.

(S8) SO_2 EMISSIONS MONITORING RECORDS [WAQSR Ch 5, Sec 2(g)(ii) & (g)(v)]
Recordkeeping for the #1 and #2 coal-fired boilers (units 14 and 15) SO_2 emissions monitoring are described under condition P60-D3 of this permit.

Reporting Requirements

(S9) SO_2 EMISSIONS TEST REPORTS [WAQSR Ch 6, Sec 3(h)(i)(C)(III)]
Reporting for any SO_2 emissions testing the Division may require for the #1 and #2 coal-fired boilers (units 14 and 15) are described under condition F30 of this permit.

(S10) SO_2 EMISSIONS MONITORING REPORTS
[WAQSR Ch 5, Sec 2(g)(iii) and 40 CFR Part 60, Subpart D]
Reporting for the #1 and #2 coal-fired boilers (units 14 and 15) SO_2 emissions monitoring are described under condition P60-D4 of this permit. For the purpose of these reports, an excess emission is defined as any two-hour period during which the average emission (arithmetic average of two contiguous one-hour periods) of SO_2 as measured by a continuous emission monitoring system exceeds the emission level of 0.2 lb/MMBtu of heat input.

SUMMARY OF SOURCE EMISSION LIMITS AND REQUIREMENTS

Source ID#: **01, 03, 09, 10, 11, 12, 13, 16 & 18** Source Description: **Various Baghouse Controlled Units Subject to CAM**

Pollutant	Emissions Limit / Work Practice Standard	Corresponding Regulation(s)	Testing Requirements	Monitoring Requirements	Recordkeeping Requirements	Reporting Requirements
Particulate	20% Opacity [F3] Various see Table I [F5]	WAQSR Ch 3, Sec 2; and Ch 6, Sec 2 Permit OP-222	Testing if required [F10]	CAM: Daily visible emissions monitoring [F13(b)(ii)] [CAM1-CAM4]	Record CAM results [F21(b)]	Semiannual reports of CAM results [F29] Report excess emissions and permit deviations [F34]

Source ID#: **22, 23 & 27** Source Description: **Baghouse Controlled Silo Vents with Emission Limits**

Pollutant	Emissions Limit / Work Practice Standard	Corresponding Regulation(s)	Testing Requirements	Monitoring Requirements	Recordkeeping Requirements	Reporting Requirements
Particulate	20% Opacity [F3] Various see Table I [F5] 500 hours of annual operation [F7(b)]	WAQSR Ch 3, Sec 2; Ch 6, Sec 2 Permit OP-222; and W.S. 35-11-206	Testing if required [F10]	Weekly visible emissions monitoring [F11(c)] Operational hours monitoring [F15]	Record VE observation results [F19(b)] Record annual hours of operation [F23]	Semiannual reports of VE observation results [F27(b)] Semiannual reports of operational hours [F31] Report excess emissions and permit deviations [F34]

Source ID#: **28** Source Description: **Baghouse Controlled Lime Storage Silo – Deca**

Pollutant	Emissions Limit / Work Practice Standard	Corresponding Regulation(s)	Testing Requirements	Monitoring Requirements	Recordkeeping Requirements	Reporting Requirements
Particulate	20% Opacity [F3] Table I [F5]	WAQSR Ch 3, Sec 2 & 11/24/89 Waiver	Testing if required [F10]	Weekly visible emissions monitoring [F11(c)]	Record VE observation results [F19(b)]	Semiannual reports of VE observation results [F27(b)] Report excess emissions and permit deviations [F34]

These tables are intended only to highlight and summarize applicable requirements for each source. The corresponding permit conditions, listed in brackets, contain detailed descriptions of the compliance requirements. Compliance with the summary conditions in these tables may not be sufficient to meet permit requirements. These tables may not reflect all emission sources at this facility.

Source ID#: **19, 20 & 21** Source Description: **Emergency Units**

Pollutant	Emissions Limit / Work Practice Standard	Corresponding Regulation(s)	Testing Requirements	Monitoring Requirements	Recordkeeping Requirements	Reporting Requirements
Particulate	30% Opacity [F3]	WAQSR Ch 3, Sec 2	Testing if required [F10]	None	Record the results of any required tests [F22]	Report the results of any required tests [F30] Report excess emissions and permit deviations [F34]

Source ID#: **07, 08 & 24** Source Description: **#1 and #2 Product Dryers and Fluid bed Product Dryer**

Pollutant	Emissions Limit / Work Practice Standard	Corresponding Regulation(s)	Testing Requirements	Monitoring Requirements	Recordkeeping Requirements	Reporting Requirements
Particulate	Annual production rate limit of 1.3 MM TPY soda ash production [F1] 20% Opacity [F3] Various see Table I [F5] Individual process rate limits [F8(b)]	WAQSR Ch 3, Sec 2, & Ch 6, Sec 2 Permits MD-462A & OP-222	Once per permit term PM test [F9(b)] Additional testing if required [F10]	CAM: once daily scrubber pressure drop and liquor flowrate monitoring [F13(b)(i)] Process and production rate monitoring [F16(b)]	Record CAM results [F21] Record the results of any required tests [F22] Record the process and production rates [F24]	Semiannual reports of CAM results [F29] Report the results of any required tests [F30] Annual process and production rate reports [F32] Report excess emissions and permit deviations [F34]

These tables are intended only to highlight and summarize applicable requirements for each source. The corresponding permit conditions, listed in brackets, contain detailed descriptions of the compliance requirements. Compliance with the summary conditions in these tables may not be sufficient to meet permit requirements. These tables may not reflect all emission sources at this facility.

Source ID#: **14 & 15** Source Description: **#1 and #2 Coal Fired Boilers**

Pollutant	Emissions Limit / Work Practice Standard	Corresponding Regulation(s)	Testing Requirements	Monitoring Requirements	Recordkeeping Requirements	Reporting Requirements
Particulate	20% Opacity [F3] [P60-D1] 0.10 lb/MMBtu PM [F5] [P60-D1] 35.85 lb/hr PM [F5] Comply with 40 CFR Part 60, Subpart D [P60-D1]	40 CFR Part 60, Subpart D; WAQSR Ch 6, Sec 2 Permit OP-222; and WAQSR Ch 7, Sec 3	Annual PM test [F9] Additional testing if required [F10]	COM for visible emissions monitoring [F11] [P60-D2] CAM: continuous opacity monitoring using COMs [F13(b)(iv)]	Record COMs data according to Subpart D [F19] [P60-D3] Record CAM results [F21]	Quarterly excess visible emission reports [F27] [P60-D4] Semiannual reports of CAM results [F29] Report excess emissions and permit deviations [F34]
SO_2	1.2 lb/MMBtu [F6] [P60-D1] 71.70 lb/hr [F6]	40 CFR Part 60, Subpart D; and WAQSR Ch 6, Sec 2 Permit OP-222	Testing if required [F10]	CEM for SO_2 emissions monitoring in accordance with Subpart D [F14] [P60-D2]	Record CEMs SO_2 data according to Subpart D [F22] [P60-D3]	Quarterly reports of excess emission in accordance with subpart D [F30] [P60-D4] Report excess emissions and permit deviations [F34]
	0.20 lb/MMBtu State Only Limitation [S4]	WAQSR Ch 3, Sec 4	Testing if required [S5]	Monitor in accordance with Subpart D [S6]	Records kept in accordance with Subpart D [S8]	Reports submitted in accordance with Subpart D [S10]
NO_X	0.70 lb/MMBtu [F6] [P60-D1] 250.95 lb/hr [F6]	40 CFR Part 60, Subpart D; and WAQSR Ch 6, Sec 2 Permit OP-222	Testing if required [F10]	CEM for NO_X emissions monitoring in accordance with Subpart D [F14] [P60-D2]	Record CEMs NO_X data according to Subpart D [F22] [P60-D3]	Quarterly reports of excess emission in accordance with subpart D [F30] [P60-D4] Report excess emissions and permit deviations [F34]
HAPs	Comply with the requirements of 40 CFR Part 63, Subpart DDDDD [P63-DDDDD1]	40 CFR Part 63, Subpart DDDDD	[P63-DDDDD2]	[P63-DDDDD3] [P63-DDDDD4]	[P63-DDDDD5] [P63-DDDDD6]	[P63-DDDDD7] [P63-DDDDD8]

These tables are intended only to highlight and summarize applicable requirements for each source. The corresponding permit conditions, listed in brackets, contain detailed descriptions of the compliance requirements. Compliance with the summary conditions in these tables may not be sufficient to meet permit requirements. These tables may not reflect all emission sources at this facility.

Source ID#: **04 & 05** Source Description: **#1 and #2 Ore Calciners**

Pollutant	Emissions Limit / Work Practice Standard	Corresponding Regulation(s)	Testing Requirements	Monitoring Requirements	Recordkeeping Requirements	Reporting Requirements
Particulate	20% Opacity [F3] 15.8 lb/hr PM [F5] 165/175 Process rate limits [F8]	WAQSR Ch 3, Sec 2, & Ch 6, Sec 2 Permit MD-462A	Once per permit term PM test [F9] Additional testing if required [F10]	COM for visible emissions monitoring [F11] CAM: once daily opacity monitoring using COMs [F13(b)(iii)] Process rate monitoring [F16(b)]	Record COMs data according Ch 5, Sec 2(g) [F19] Record CAM results [F21] Record the results of any required tests [F22] Record the process rates [F24]	Quarterly excess opacity and monitoring system reports [F27] Semiannual reports of CAM results [F29] Report the results of any required tests [F30] Annual process rate reports [F32] Report excess emissions and permit deviations [F34]
SO_2	0.00 lb/hr [F6]	WAQSR Ch 6, Sec 2 Permit MD-462A	Additional testing if required [F10]	None [F14(c)]	Record the results of any required tests [F22]	Report the results of any required tests [F30] Report excess emissions and permit deviations [F34]
NO_X	0.15 lb/MMBtu & 30.00 lb/hr [F6]	WAQSR Ch 6, Sec 2 Permit MD-462A	Additional testing if required [F10]	Annual NO_X emissions monitoring [F14(b)]	Record the results of the NO_X monitoring [F22] Record the results of any required tests [F22]	Semiannual reports of NO_X emissions [F30] Report the results of any required tests [F30] Report excess emissions and permit deviations [F34]
CO	Operate in accordance with the CO minimization plan [F7]	WAQSR Ch 6, Sec 2 Permit MD-462A	Testing if required [F10]	None	Record deviations from the CO minimization plan [F23]	Report deviations from the CO minimization plan [F31] Report excess emissions and permit deviations [F34]

These tables are intended only to highlight and summarize applicable requirements for each source. The corresponding permit conditions, listed in brackets, contain detailed descriptions of the compliance requirements. Compliance with the summary conditions in these tables may not be sufficient to meet permit requirements. These tables may not reflect all emission sources at this facility.

ABBREVIATIONS

AQD	Air Quality Division
BACT	Best available control technology (see Definitions)
Btu	British Thermal Unit
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
C.F.R.	Code of Federal Regulations
CO	Carbon monoxide
°F	Degrees Fahrenheit
DEQ	Wyoming Department of Environmental Quality
EPA	United States Environmental Protection Agency (see Definitions)
g/hp-hr	Gram(s) per horsepower hour
gal	Gallon(s)
H_2S	Hydrogen sulfide
HAP(s)	Hazardous air pollutant(s)
hp	Horsepower
hr	Hour(s)
ID#	Identification number
lb	Pound(s)
M	Thousand
MACT	Maximum available control technology (see Definitions)
mfr	Manufacturer
mg	Milligram(s)
MM	Million
MVAC	Motor Vehicle Air Conditioner
N/A	Not applicable
NMHC(s)	Non-methane hydrocarbon(s)
NO_X	Oxides of nitrogen
O_2	Oxygen
OPP	Operating Permit Program
PM	Particulate matter
PM_{10}	Particulate matter less than or equal to a nominal diameter of 10 micrometers
ppmv	Parts per million (by volume)
ppmw	Parts per million (by weight)
QIP	Quality Improvement Plan
SCF	Standard cubic foot (feet)
SCFD	Standard cubic foot (feet) per day
SCM	Standard cubic meter(s)
SIC	Standard Industrial Classification
SO_2	Sulfur dioxide
SO_3	Sulfur trioxide
SO_x	Oxides of sulfur
TBD	To be determined
TPY	Tons per year
U.S.C.	United States Code
μg	Microgram(s)
VOC(s)	Volatile organic compound(s)
W.S.	Wyoming Statute
WAQSR	Wyoming Air Quality Standards & Regulations (see Definitions)

DEFINITIONS

"Act" means the Clean Air Act, as amended, 42 U.S.C. 7401, et seq.

"Administrator" means Administrator of the Air Quality Division, Wyoming Department of Environmental Quality.

"Applicable requirement" means all of the following as they apply to emissions units at a source subject to Chapter 6, Section 3 of the WAQSR (including requirements with future effective compliance dates that have been promulgated or approved by the EPA or the State through rulemaking at the time of issuance of the operating permit):

(a) Any standard or other requirement provided for in the Wyoming implementation plan approved or promulgated by EPA under title I of the Act that implements the relevant requirements of the Act, including any revisions to the plan promulgated in 40 C.F.R. Part 52;

(b) Any standards or requirements in the WAQSR which are not a part of the approved Wyoming implementation plan and are not federally enforceable;

(c) Any term or condition of any preconstruction permits issued pursuant to regulations approved or promulgated through rulemaking under title I, including parts C or D of the Act and including Chapter 5, Section 2 and Chapter 6, Sections 2 and 4 of the WAQSR;

(d) Any standard or other requirement promulgated under Section 111 of the Act, including Section 111(d) and Chapter 5, Section 2 of the WAQSR;

(e) Any standard or other requirement under Section 112 of the Act, including any requirement concerning accident prevention under Section 112(r)(7) of the Act and including any regulations promulgated by EPA and the State pursuant to Section 112 of the Act;

(f) Any standard or other requirement of the acid rain program under title IV of the Act or the regulations promulgated thereunder;

(g) Any requirements established pursuant to Section 504(b) or Section 114(a)(3) of the Act concerning enhanced monitoring and compliance certifications;

(h) Any standard or other requirement governing solid waste incineration, under Section 129 of the Act;

(i) Any standard or other requirement for consumer and commercial products, under Section 183(e) of the Act (having to do with the release of volatile organic compounds under ozone control requirements);

(j) Any standard or other requirement of the regulations promulgated to protect stratospheric ozone under title VI of the Act, unless the EPA has determined that such requirements need not be contained in a title V permit;

(k) Any national ambient air quality standard or increment or visibility requirement under part C of title I of the Act, but only as it would apply to temporary sources permitted pursuant to Section 504(e) of the Act; and

(l) Any state ambient air quality standard or increment or visibility requirement of the WAQSR.

(m) Nothing under paragraphs (a) through (l) above shall be construed as affecting the allowance program and Phase II compliance schedule under the acid rain provision of Title IV of the Act.

"BACT" or "Best available control technology" means an emission limitation (including a visible emission standard) based on the maximum degree of reduction of each pollutant subject to regulation under the WAQSR or regulation under the Federal Clean Air Act, which would be emitted from or which results for any proposed major emitting facility or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application or production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular class of sources would make the imposition of an emission standard infeasible, he may instead prescribe a design, equipment, work practice or operational standard or combination thereof to satisfy the requirement of Best Available Control Technology. Such standard shall, to the degree possible, set forth the emission reduction achievable by implementation of such design, equipment, work practice, or operation and shall provide for compliance by means which achieve equivalent results. Application of BACT shall not result in emissions in excess of those allowed under Chapter 5, Section 2 of the WAQSR and any other new source performance standard or national emission standards for hazardous air pollutants promulgated by EPA but not yet adopted by the state.

"Department" means the Wyoming Department of Environmental Quality or its Director.

"Director" means the Director of the Wyoming Department of Environmental Quality.

"Division" means the Air Quality Division of the Wyoming Department of Environmental Quality or its Administrator.

"Emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

"EPA" means the Administrator of the U.S. Environmental Protection Agency or the Administrator's designee.

"Fuel-burning equipment" means any furnace, boiler apparatus, stack, or appurtenances thereto used in the process of burning fuel or other combustible material for the purpose of producing heat or power by indirect heat transfer.

"Fugitive emissions" means those emissions which could not reasonably pass through a stack chimney, vent, or other functionally equivalent opening.

"Insignificant activities" means those activities which are incidental to the facility's primary business activity and which result in emissions of less than one ton per year of a regulated pollutant not included in the Section 112 (b) list of hazardous air pollutants or emissions less than 1000 pounds per year of a pollutant regulated pursuant to listing under Section 112 (b) of the Act provided, however, such emission levels of hazardous air pollutants do not exceed exemptions based on insignificant emission levels established by EPA through rulemaking for modification under Section 112 (g) of the Act.

"MACT" or "Maximum achievable control technology" means the maximum degree of reduction in emissions that is deemed achievable for new sources in a category or subcategory that shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source, as determined by the Administrator. Emission standards promulgated for existing sources in a category or subcategory may be less stringent than standards for new sources in the same category or subcategory but shall not be less stringent, and may be more stringent than:

(a) the average emission limitation achieved by the best performing 12 percent of the existing sources (for which the Administrator has emission information), excluding those sources that have, within 18 months before the emission standard is proposed or within 30 months before such standard is promulgated, whichever is later, first achieved a level of emission rate or emission reduction which complies, or would comply if the source is not subject to such standard, with the lowest achievable emission rate applicable to the source category and prevailing at the time, in the category or subcategory for categories and subcategories with 30 or more sources, or

(b) the average emission limitation achieved by the best performing five sources (for which the Administrator has or could reasonably obtain emissions information) in the category or subcategory for categories or subcategories with fewer than 30 sources.

"Modification" means any physical change in, or change in the method of operation of, an affected facility which increases the amount of any air pollutant (to which any state standards applies) emitted by such facility or which results in the emission of any such air pollutant not previously emitted.

"Permittee" means the person or entity to whom a Chapter 6, Section 3 permit is issued.

"Potential to emit" means the maximum capacity of a stationary source to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation is enforceable by EPA and the Division. This term does not alter or affect the use of this term for any other purposes under the Act, or the term "capacity factor" as used in title IV of the Act or the regulations promulgated thereunder.

"Regulated air pollutant" means the following:

(a) Nitrogen oxides (NO_X) or any volatile organic compound;

(b) Any pollutant for which a national ambient air quality standard has been promulgated;

(c) Any pollutant that is subject to any standard established in Chapter 5, Section 2 of the WAQSR or Section 111 of the Act;

(d) Any Class I or II substance subject to a standard promulgated under or established by title VI of the Act; or

(e) Any pollutant subject to a standard promulgated under Section 112 or other requirements established under Section 112 of the Act, including Sections 112(g), (j), and (r) of the Act, including the following:

(i) Any pollutant subject to requirements under Section 112(j) of the Act. If EPA fails to promulgate a standard by the date established pursuant to Section 112(e) of the Act, any pollutant for which a subject source would be major shall be considered to be regulated on the date 18 months after the applicable date established pursuant to Section 112(e) of the Act; and

(ii) Any pollutant for which the requirements of Section 112(g)(2) of the Act have been met, but only with respect to the individual source subject to Section 112(g)(2) requirement.

(f) Pollutants regulated solely under Section 112(r) of the Act are to be regulated only with respect to the requirements of Section 112(r) for permits issued under this Chapter 6, Section 3 of the WAQSR.

"Renewal" means the process by which a permit is reissued at the end of its term.

"Responsible official" means one of the following:

(a) For a corporation:

(i) A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation; or

(ii) A duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(A) the facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(B) the delegation of authority to such representative is approved in advance by the Division;

(b) For a partnership or sole proprietorship: a general partner or the proprietor, respectively;

(c) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency; or

(d) For affected sources:

(i) The designated representative or alternate designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Act or the regulations promulgated thereunder are concerned; and

(ii) The designated representative, alternate designated representative, or responsible official under Chapter 6, Section 3 (b)(xxvi) of the WAQSR for all other purposes under this section.

"WAQSR" means the Wyoming Air Quality Standards and Regulations promulgated under the Wyoming Environmental Quality Act, W.S. §35-11-101, et seq.

Appendix A
Fugitive Emissions Control Plan

TG SODA ASH INC.
RESPONSE TO THE AQD INSPECTION REPORT

In the 1986 Air Quality Inspection Report eight "Air Quality Concerns" were listed which dealt primarily with fugitive dust control at our Granger facility. In addition a request was made to retest the particulate emission rates of the ore crushing baghouse and the ash handling baghouse to demonstrate that these facilities are meeting the emission rates that were established in permit #MD-69.

The following is a response to the eight concerns outlined in the inspection report which includes descriptions of our dust control efforts and a schedule for retesting the two baghouses.

1. DUST CONTROL EQUIPMENT SPECIFICATIONS

After studying the dust control system at product loadout it was determined that the existing baghouse was adequate to collect dust from the railcar loading facility and the truck loading facility. A drawing of the duct work and a description of the loading spout for the truck loading facility is in pocket #1.

2. COAL STOCK PILE DUST CONTROL

Several methods of controlling dust on the coal pile were investigated and it has been decided to apply a polymer based dust suppressant to the coal as it is being unloaded from the railcars. This type of suppressant has a residual effect that will reduce wind losses from the pile as well as reduce the amount of dust that is generated when coal is reclaimed from the pile

A drawing of the spray system in the coal unloading building and additional information about polymer based dust suppressants can be found in pocket #2 We anticipate beginning application of the material by mid-December.

3. COAL HANDLING DUST SUPPRESSION SYSTEM

A drawing of the dust control system in the coal reclaim building is in pocket #3 as well as an information sheet of the wetting agent that is currently being used. The sprays on the reclaim hopper are activated by remote control as coal is dumped into the hopper. The sprays on transfer points are activated by a tilt switch on the apron feeder.

4. TRONA STOCK PILE DUST CONTROL

The haul road from the reserve ore pile is watered every four hours during reclaim operations. To further reduce the amount of fugitive dust that is generated during this operation, high walls are maintained on either side of the area being stripped. Our ambient air data indicate that the losses from the pile are small.

5. EMERGENCY RESERVE TRONA ORE STOCKPILE SIZE

At the current time the mine production and mill production are closely matched; therefore, there is not much demand for stockpile ore. Moving the pile "just to be moving it" rather than consuming it would result in unnecessary dust generation. However we are in the process of changing our mining plan for the next year and we will include provisions for reducing by consuming the reserve pile to 150,000 tons by January of 1989. Most of the reduction will occur during June through September of 1988 so as to reduce the amount of overtime that is worked during the peak vacation season.

6 RAILCAR LOADOUT OPERATING PRACTICES

As was indicated in my 6/10/87 letter the problem with the dust hood was an isolated incidence and it is our practice to keep all dust control equipment operational. We have reviewed our operating and maintenance guidelines and believe they are adequate to prevent further occurrences of the type referenced.

7. <u>CEM EXCESS EMISSION REPORTS</u>

We are pleased to have our computer system working properly and generating accurate reports.

8. <u>NON-COMPLIANCE SOURCES</u>

As we discussed over the telephone we have scheduled to begin stack testing on the ore crusher baghouse and on the ash handling baghouse on 11/9/87. We should have a report on the test results ready for submittal by 12/15/87.

Appendix B

Calciner Burner Operational Plan

June 13, 1995

Mr. Bernard J. Dailey
Engineering Supervisor
Wyoming Dept. of Environmental Quality
Air Quality Division
122 West 25th Street
Cheyenne, WY 82002

Dear Mr. Dailey:

In response to condition #9 of the permit to increase ore feed rates to the two calciners, Tg Soda Ash is submitting an operational plan to confirm continued optimal performance of the calciners' natural gas burners.

Each calciner is equipped with an Ametek/Thermox gas analyzer that provides for continuous measurement of the percent excess oxygen (%O_2) within the furnace box of each respective unit. The operational plan is established around these analyzers as follows:

- Continuous %O_2 output for each analyzer will be displayed on the Moore DCS screen in conjunction with the other parameters controlling calciner operation.

- A range of 3% to 14% excess oxygen will define operational acceptability for proper burner combustion. An alarm will activate whenever the excess oxygen falls beyond this range, thus requiring operator attention.

- The operator will initiate action to acknowledge the alarm and to correct the problem, through verification of the %O_2 reading and/or maintenance to the gas burner(s).

- Excess %O_2 data on each calciner will be archived on the Moore DCS data historian to provide documentation of burner operation. These data will be available for inspection by the Division and will be on file for three (3) years.

- A quarterly P/M schedule for the oxygen analyzers will be followed as recommended by the manufacturer. Documentation of these activities will be available from the work order history on the facility's AS 400 work order management system.

- The operational plan will be in effect no later than sixty (60) days from issuance of the affected permit by the Division.

Tg Soda Ash feels confident that the above plan will document the continued proper operation of the calciner gas burners and provide the Division with a mechanism to assure that CO emissions from the burners remain at minimal levels as previously demonstrated by testing.

June 13, 1995

Mr. Bernard J. Dailey
WDEQ, AQD
Cheyenne, WY 82002

If you have any questions regarding the operational plan as proposed in this letter, please do not hesitate to contact me.

Sincerely,

Michael D. Wendorf
Environmental Engineer, AEP

cc: Mr. Lee Gribovicz
WDEQ AQD
250 Lincoln St.
Lander, WY 82987

Appendix C

Compliance Assurance Monitoring Plans

COMPI .NCE ASSURANCE MONIT(.NG PLAN
Baghouses

Emissions Unit

Description:	Baghouse (9)
Identification:	UIN-01, -03, -09, -10, -11, -12, -13, -16, -18
Facility:	FMC Granger Soda Ash Facility

Applicable Regulation, Emission Limit, and Monitoring Requirements

Regulation No.:	OP-222, 30-083	
Emission Limit:	20% Opacity (all)	
UIN-01 1.03 lb/hr PM	UIN-03 2.14 lb/hr PM	UIN-09 2.57 lb/hr PM
UIN-10 2.14 lb/hr PM	UIN-11 2.57 lb/hr PM	UIN-12 2.57 lb/hr PM
UIN-13 1.31 lb/hr PM	UIN-16 0.43 lb/hr PM	UIN-18 1.33 lb/hr PM

Monitoring Requirements: CAM for PM, periodic for visible emissions

Control Technology

Pulse-jet baghouse operated under negative pressure.

Monitoring Approach

Indicator

Daily visible emissions (VE) observations.

Rationale

No visible emissions provide reasonable assurance of compliance for both opacity and particulate limits. Observed visible emissions indicate abnormal baghouse collection efficiency.

Measurement

VE observations will be made following appropriate criteria for location, background, etc., similar to EPA Method 22 requirements. Observation results will be recorded in a logbook with the date, time, weather conditions, presence or absence of a plume, any corrective action taken, and identification of the observer.

Analytical Devices Required

None

QA/QC Procedures

Observers will be properly trained to conduct observations using EPA Method 22 as a guideline.

Indicator Range

Presence of a VE will initiate corrective action directed at the baghouse unit.

Monitoring Report

A report will be submitted semi-annually and will include the number, duration, the cause of the episodes when the VE indicated a plume, and the corrective actions taken.

QIP (Quality Improvement Plan) Threshold

The QIP threshold is nine (9) positive VE observations in a six-month period. This level is 5 percent of the total daily readings. If the QIP threshold is exceeded in a semi-annual reporting period, a QIP will be developed and implemented. The threshold of 5% was used as recommended in EPA's CAM Technical Guidance Document.

Implementation Pl-

Daily VE observatior. .ill be initiated at the startup of the Ja ash plant, or in the event that the plant is operating prior to the date of the operating permit renewal, no longer than 30 days from the renewal date.

FMC Granger Operating Permit No. 31-083
CAM Plan Addendum No. 1

Subject: Length of daily baghouse visual observation and justification

Affected Units:UIN-01, 03, 09, 10, 11, 12, 13, 18

The proposed CAM plan for each of the above specified units calls for one daily visual observation to be conducted. The absence of a plume will indicate proper control equipment operation and compliance with both particulate and opacity limits. An observed plume will indicate abnormal baghouse collection efficiency, and immediate action will be initiated to correct the problem.

The length of the daily observation is proposed to be **continuous for one minute per stack.** It is believed that this time interval is sufficient to visually confirm either: (1) normal operation of the baghouse when no visible plume is present, or; (2) a baghouse whose control efficiency has deteriorated to the point of marginal compliance when a persistent plume can be observed.

The presence of a persistent plume will be detectable within a one-minute observation period, and indicates to the operator that the condition of the baghouse is such that immediate corrective action is necessary. Intermittent or occasional faint puffs from a baghouse, if observed, may well indicate the potential for future corrective action, but would not constitute an immediate compliance issue. An EPA Method 5 particulate stack emission test encompasses a 3-hour test period. It is reasonable to expect a baghouse with an intermittent puff to successfully pass a 3-hour Method 5 test; the same could not be said of a baghouse displaying a persistent plume.

Furthermore, it can be extremely difficult to find the bag(s) that may be responsible for an intermittent puff. An entire baghouse filter change may be necessary to find the suspect bag(s), and as discussed above, compliance is likely not at risk from an intermittent condition.

COMPLIANCE ASSURANCE MONITORING PLAN
Product Dryer Scrubbers

Emissions Unit

Description:	Venturi Scrubber (3)
Identification:	UIN-07, -08, -24
Facility:	FMC Granger Soda Ash Facility

Applicable Regulation, Emission Limit, and Monitoring Requirements

Regulation No.:	OP-222, 30-083
Emission Limit:	UIN-07, -08 3.94 lb/hr PM UIN-24 1.00 lb/hr PM
Monitoring Requirements:	CAM for PM

Control Technology

Venturi scrubber, adjustable damper

Monitoring Approach

Indicators

Pressure differential, scrubber liquor flow

Rationale

Periodic monitoring was required for each unit under permit 30-083. Scrubber differential pressure across the venturi and scrubber liquor flow rate were selected as the two critical parameters to evaluate PM compliance. EPA Method 9 tests were conducted to determine the acceptable range of the two parameters for each source. The selected ranges for this CAM mirror the ranges adopted for periodic monitoring. The frequency of measurements has been increased from weekly to daily to satisfy CAM requirements.

Measurement

Daily dP and liquor flow rate indications will be observed by the operator and recorded. If either parameter is observed to be outside its accepted range, the exceedance of the CAM range will be noted and changes to dryer operation are necessary.

Analytical Devices Required

dP indicator in inches w.c., flow meter installed in scrubber liquor line displaying gpm

QA/QC Procedures

Calibration and maintenance of the instrumentation will be conducted per manufacturer's specifications.

Indicator Range	UIN-07	UIN-08	UIN-24
Acceptable dP range, in. w.c.:	19-35	16-31	18-33
Acceptable liquor flow rate, gpm:	147–273	135-252	43-81

Monitoring Report

A report will be submitted semi-annually and will include the number, duration, the cause of the episodes when the scrubber operates outside either the dP or liquor flow rate CAM ranges, and the corrective actions taken to return the indicators to acceptable levels.

QIP (Quality Improvement Plan) Threshold

The QIP threshold is a cumulative total of no more than 5% of the hours of unit operation outside the dP or liquor flow rate ranges. If the QIP threshold is exceeded in a semi-annual reporting period, a QIP will be developed and implemented. The threshold of 5% was used as recommended by EPA's CAM Technical Document.

Implementation Plan

Continuous observations will be initiated no more than 90 days from the startup of the soda ash plant, or in the event that the plant is operating prior to the date of the operating permit renewal, no longer than 90 days from the renewal date.

COMPLIANCE ASSURANCE MONITORING PLAN
Trona Calciner ESPs

Emissions Unit

Description:	Trona Calciner (2)
Identification:	UIN-04, -05
Facility:	FMC Granger Soda Ash Facility

Applicable Regulation, Emission Limit, and Monitoring Requirements

Regulation No.:	OP-222, 30-083
Emission Limit:	UIN-04, -05 15.8 lb/hr PM
Monitoring Requirements:	CAM for PM

Control Technology

Buell electrostatic precipitator, 4 fields

Monitoring Approach

Indicators

Opacity measurements from installed COMS.

Rationale

Opacity demonstrates a reasonable indication of PM compliance. Operation above the demonstrated opacity limit indicates deterioration of collection efficiency (see detailed attachment).

Measurement

Continuous opacity measurements from the COMS will verify normal operation. When 6-min opacity averages exceed 7% PM collection efficiency is reduced and changes to calciner operation are necessary.

Periods of startup and shutdown of the unit are acknowledged to be abnormal conditions and the only reasonable actions available regarding calciner operation will be to limit the duration of the episode.

Analytical Devices Required

COMS, data acquisition system.

QA/QC Procedures

COMS follows the quarterly opacity filter audit requirements.

Indicator Range

Greater than 7% opacity will trigger an alarm on the operator screen to adjust calciner operation.

Monitoring Report

A report will be submitted semi-annually and will include the number, duration, the cause of the episodes when the opacity limit was exceeded and the corrective actions taken to return the indicator to acceptable levels.

QIP (Quality Improvement Plan) Threshold

The QIP threshold is a cumulative total of no more than 5% of the hours of unit operation exceeding the opacity limit. If the QIP threshold is exceeded in a semi-annual reporting period, a QIP will be developed and implemented. Unit startup and shutdown episodes will not be counted toward the QIP threshold, but are acknowledged periods of excess PM emissions. Therefore, it is not reasonable to assess the performance of the CAM plan by including these episodes in the evaluation. The threshold of 5% was used as recommended in EPA's CAM Technical Document.

Implementation Plan

Continuous observations will be initiated no more than 90 days from the startup of the soda ash plant, or in the event that the plant is operating prior to the date of the operating permit renewal, no longer than 90 days from the renewal date.

Rationale for Monitoring Approach

Background

FMC Granger operates two trona ore calciners, each of which has a multi-clone cyclone separator followed by a Buell electrostatic precipitator for collection of particulate matter (PM). Each ESP has four (4) electrical fields, designated A, B, C, D. Power control for each field is managed by a PrecipTech SQ300 software-based management system, with user availability of secondary current outputs for each field.

Rationale for Performance Indicator and Range

A trona ore calciner is essentially a rotary kiln, in this case indirectly fired by natural gas burners. Crushed ore is introduced into the calciner at the 'throat' and comes in contact with the heated air stream via the tumbling effect of the rotating calciner shell. This operation releases particulate matter that is carried out of the calciner via the exhaust air and proceeds first through a multi-clone cyclone. The cyclone is capable of collecting 70-80% of the total particulate load. The exhaust then proceeds through the ESP, which captures up to 99.7% of the remaining particulate. The exhaust is then drawn through an ID fan and exits the stack.

Factors that can affect the amount of PM generated in this operation include:

- feed rate of ore into the calciner
- screen size of the crushed ore
- air flow velocity

The CAM indicator selected is stack opacity. Stack emission test data collected over the course of eight years indicate that the opacity can provide reliable indications of PM collection efficiency.

Stack testing has shown that PM emissions with associated opacity values up to at least 7% are below the PM limit of 15.8 lb/hr. Since the conversion of the two calciners from coal firing to natural gas firing in 1993, a combined total of 21 one-hour EPA Method 5/202 runs have been conducted at nearly every possible normal operating condition. These tests have all been submitted to the Division. The two highest PM emission results were evaluated for corresponding opacity:

Date	Unit	Feed Rate	KACFM	gr/ACF	PM Result	Opacity
08/1993	#1 Calciner	167 TPH	285.3	0.00149	13.1 lb/hr	5.9%
08/1993	#2 Calciner	151 TPH	264.7	0.00154	12.9 lb/hr	6.2%

At the time of these tests, the COMS for these units had not yet been placed into service (1995). Therefore, opacity was calculated using the following equation:

Opacity, % = 100 * (1-EXP(-E* c * L), where

E = extinction coefficient (1.2)
c = particle concentration, gr/acf
L = stack diameter, ft (9.5)

Rationale for Performance Indicator and Range, cont'd.

After installation of the COMS, subsequent stack tests had actual measured opacity information. From these later tests, an extinction coefficient *E* could be determined and used to estimate opacities prior to 1995. A value of 1.2 is used as a conservative estimate for *E* based on the COMS data.

CAM Plan Application

The installed COMS allows for the continuous monitoring of opacity and, if opacity increased beyond the 7% trigger, operation of the ESP and calciner will be evaluated and adjusted as necessary to return opacity to levels at or below 7%.

COMPL. .NCE ASSURANCE MONITC .NG PLAN
UIN-14 No. 1 Coal Boiler ESP

Emissions Unit

Description:	Coal Boiler
Identification:	UIN-14
Facility:	FMC Granger Soda Ash Facility

Applicable Regulation, Emission Limit, and Monitoring Requirements

Regulation No.:	OP-222, 30-083
Emission Limit:	0.10 lb/MMBTU, 35.85 lb/hr PM
Monitoring Requirements:	CAM for PM

Control Technology

Belco electrostatic precipitator, 4 fields

Monitoring Approach

Indicators

Opacity measurements from installed COMS, regression equation to predict exhaust gas airflow based on steam rate, regression equation to predict gr/dscf PM emission based on COMS opacity.

Rationale

Opacity demonstrates a reasonable indication of PM compliance. Operation above the predicted opacity limit indicates deterioration of PM collection efficiency.(see detailed attachment).

Periods of startup and shutdown of the unit are acknowledged to be abnormal conditions and the only reasonable actions available regarding boiler operation will be to limit the duration of the episode.

Measurement

Continuous opacity measurements from the COMS are monitored to ensure an opacity level below the upper CAM opacity limit.

Analytical Devices Required

Continuous opacity monitoring system (COMS), data acquisition system (DAS) to calculate PM emissions from corresponding opacity values and to provide an operator alarm.

QA/QC Procedures

COMS follows the required quarterly opacity filter audit; data from annual emission stack tests will be added to the data set initially used to define the regression and in so doing the regression will continue to be further refined and QA-checked.

Indicator Range

An excursion of the CAM range will occur when a rolling 3-hour average opacity exceeds 23.9%. This favorably parallels the required 3-hour test time to conduct an EPA Method 5 compliance test.

Monitoring Report

A report will be subm. .d quarterly and will include the numL , duration, the cause of the excursions from the CAM opacity range, and the corrective actions taken to return the indicator to acceptable levels.

QIP (Quality Improvement Plan) Threshold

The QIP threshold is a cumulative total of no more than 5% of the hours of unit operation outside the CAM opacity range. If the QIP threshold is exceeded in a quarterly reporting period, a QIP will be developed and implemented. The threshold of 5% was used as recommended by EPA's CAM Technical Guidance Document.

Unit startup and shutdown episodes will not be counted toward the QIP threshold, but are acknowledged periods of excess PM emissions. Therefore, it is not reasonable to assess the performance of the CAM plan by including these episodes in the evaluation.

Rationale for Monitoring Approach

Background

FMC Granger operates two spreader stoker coal-fired steam boilers, each of which has a multi-clone cyclone separator followed by a Belco electrostatic precipitator for collection of particulate matter (PM). Each boiler has a full complement of COMS/CEMS instrumentation to monitor stack gas emissions and opacity.

The spreader stoker boiler uses mechanical feeders to distribute coal uniformly over the surface of a moving grate. Introducing the fuel into the furnace and onto the grate results in combustion of coal both on the moving grate as well as in suspension directly above the grate. The amount of fuel burned in suspension depends primarily on fuel size and composition, and airflow velocity. Generally, fuels with finer size distributions, higher volatile matter, and lower moisture contents result in a greater percentage of combustion and corresponding heat release rates in suspension above the bed.

This combustion arrangement produces particulate matter in the form of fly ash and partially burned coal that is entrained in the flue gas. The gas proceeds first through a multi-clone cyclone. The cyclone is capable of collecting up to 70% of the total particulate load. The exhaust then proceeds through the ESP, which captures up to 99.7% of the remaining particulate. The exhaust then passes through an economizer, an ID fan, and an FGD scrubber before exiting the stack.

Operational factors that can affect the amount of PM generated include:

- steam production rate of the boiler
- screen size of the stoker coal
- flue gas velocity
- combustion efficiency

Rationale for Performance Indicators and Ranges

The CAM plan for the boiler was developed using information from EPA Method 5 emission tests conducted from 1992 – 2000 and from corresponding opacities via COMS.

After thorough review of the available stack test information and from process knowledge of the coal combustion process and of stoker boiler performance in particular, the following conclusion could be drawn: opacity is the most useful real-time parameter to estimate real-time PM emissions. Rigorous statistical analyses verified that opacity is the only parameter that has reasonable correlation with PM. Operating rate, flue gas volume, ESP secondary current, and CO emission levels all influence changes in opacity and PM emission rates, but singularly do not statistically correlate with PM emissions.

Two regressions were developed in order to obtain the information necessary for correlating opacity and gr/dscf. The first regression predicts exhaust gas flow rate in dry standard cubic feet per minute (DSCFM) based on the steam production rate. A linear regression is used with a data set of n = 13, gathered from stack tests conducted over a wide range of steam rates:

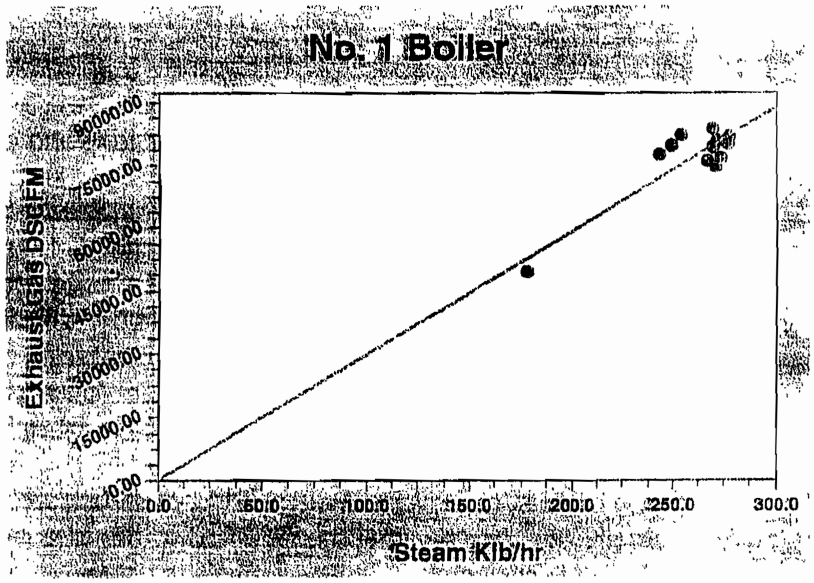
12-23-2005 031083

Steam rate vs DSCFM

Linear Fit: y=a+bx

Coefficient Data:

a =	320.3
b =	294.7
r =	0.984
S =	4100.9
Coeff of var =	5%



Using the regression, the exhaust gas rate in DSCFM can be estimated for any steam rate. For example, with x = 300 thousand pound per hour (Klb/hr) steam rate (100% capacity):

$$y = a + bx$$
$$y = 320.3 + 294.7 * 300$$
$$y = 88730 \text{ DSCFM}$$

The DSCFM number is important, as it allows one to back-calculate the maximum allowable grains per dry standard cubic feet per minute (gr/dscf) emission for a given steam rate (heat input in MMBTU/hr).

At the permitted emission rate of 0.1 lb/MMBTU and with UIN-14 Boiler No. 1 rated at 358.5 MMBTU/hr @ 300 Klb/hr steam production:

0.10 lb/MMBTU * 358.5 MMBTU/hr = 35.85 lb/hr PM mass emission limit

Converting lb/hr into gr/min:

35.85 lb/hr * 7000 gr/lb ÷ 60min/hr = 4182.5 gr/min

Using the estimated flow rate from the regression, the maximum PM emission rate in gr/dscf can be estimated:

4182.5 gr/min ÷ 88730 DSCFM = 0.0471 gr/dscf

To account for inherent error in the flow rate regression, the coefficient of variation of 5% is applied to the emission, resulting in the most conservative estimate:

4182.5 gr/min ÷ (88730 DSCFM*1.05) = **0.0449 gr/DSCF**

This defines the ma m allowable *mass* emission at the i ium steam rate (35.85 lb/hr). It also defines the maximum emission on a *rate* basis (0.10 lb/MMBTU) throughout the entire boiler operating range.
The boiler firing rate is considered proportional to the steam rate, and therefore proportional to the air flow rate. Three examples of various steam rates indicate that essentially the same PM concentration applies in all three cases:

Steam Rate	Steam Klbs/hr	DSCFM	MMBTU/hr	gr/DSCF@0.10 lb/MMBTU
100%	300	88730	358.5	0.0449
75%	225	66628	268.9	0.0448
50%	150	44525	179.3	0.0447

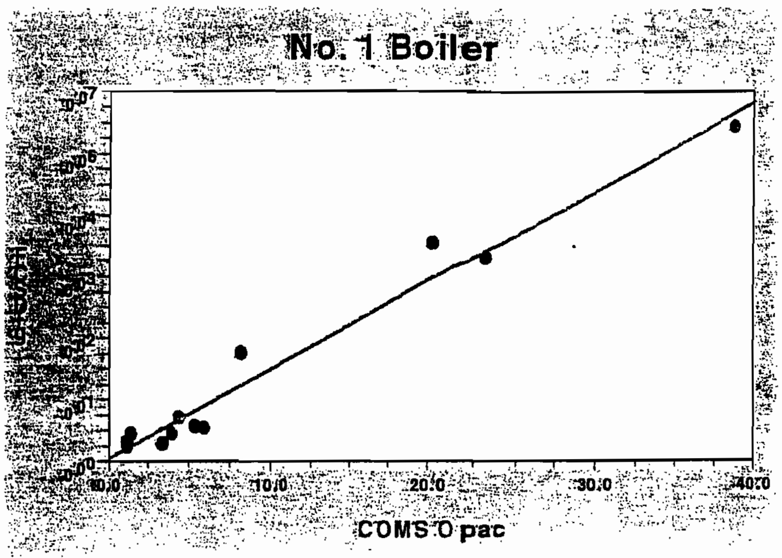
The second regression predicts actual PM emission based on opacity. A linear regression is used with a data set of n = 12:

Opacity vs gr/dscf

Linear Fit: y=a+bx

Coefficient Data:

a =	0.00056
b =	0.001594
r =	0.986
S =	0.0033
Coeff. of Var.	18%



Solving for x (opacity), one can predict the maximum opacity allowable to not exceed the 0.0449 gr/dscf limit:

$$x = (y - a) \div b$$

$$(0.0449 - 0.00056) / 0.001594 = 27.8$$

Again to account for inherent error in the emission regression, the coefficient of variation of 18% is applied to the opacity to result in the most conservative estimate:

$27.8 \div 1.18 =$ **23.6% opacity**

CAM Plan Application

Application of this CAM plan is as follows - if a rolling 3-hour average opacity exceeds 23.6% at any boiler operating rate, adjustments to boiler operation are necessary. These adjustments can range from optimizing the fuel/air ratio, adjusting coal feeders, increasing precipitator power, etc. However, because the upper CAM limit of opacity is above the already established 20% opacity limitation, action is imminent even before reaching the CAM trigger.

COMPL...NCE ASSURANCE MONITC .NG PLAN
UIN-15 No. 2 Coal Boiler ESP

Emissions Unit

Description:	Coal Boiler
Identification:	UIN-15
Facility:	FMC Granger Soda Ash Facility

Applicable Regulation, Emission Limit, and Monitoring Requirements

Regulation No.:	OP-222, 30-083
Emission Limit:	0.10 lb/MMBTU, 35.85 lb/hr PM
Monitoring Requirements:	CAM for PM

Control Technology

Belco electrostatic precipitator, 4 fields

Monitoring Approach

Indicators

Opacity measurements from installed COMS, regression equation to predict exhaust gas airflow based on steam rate, regression equation to predict gr/dscf PM emission based on COMS opacity.

Rationale

Opacity demonstrates a reasonable indication of PM compliance. Operation above the predicted opacity limit indicates deterioration of PM collection efficiency.(see detailed attachment).

Periods of startup and shutdown of the unit are acknowledged to be abnormal conditions and the only reasonable actions available regarding boiler operation will be to limit the duration of the episode.

Measurement

Continuous opacity measurements from the COMS are monitored to ensure an opacity level below the upper CAM opacity limit.

Analytical Devices Required

Continuous opacity monitoring system (COMS), data acquisition system (DAS) to calculate PM emissions from corresponding opacity values and to provide an operator alarm.

QA/QC Procedures

COMS follows the required quarterly opacity filter audit; data from annual emission stack tests will be added to the data set initially used to define the regression and in so doing the regression will continue to be further refined and QA-checked.

Indicator Range

An excursion of the CAM range will occur when a rolling 3-hour average opacity exceeds 15.2%. This favorably parallels the required 3-hour test time to conduct an EPA Method 5 compliance test.

Monitoring Report

A report will be subm. .d quarterly and will include the num. , duration, the cause of the episodes when the CAM opacity limit is exceeded, and the corrective actions taken to return the indicator to acceptable levels.

QIP (Quality Improvement Plan) Threshold

The QIP threshold is a cumulative total of no more than 5% of the hours of unit operation outside the CAM opacity range. If the QIP threshold is exceeded in a quarterly reporting period, a QIP will be developed and implemented. The threshold of 5% was used as recommended by EPA's CAM Technical Guidance Document.

Unit startup and shutdown episodes will not be counted toward the QIP threshold, but are acknowledged periods of excess PM emissions. Therefore, it is not reasonable to assess the performance of the CAM plan by including these episodes in the evaluation.

Rationale for Monitoring Approach

Background

FMC Granger operates two spreader stoker coal-fired steam boilers, each of which has a multi-clone cyclone separator followed by a Belco electrostatic precipitator for collection of particulate matter (PM). Each boiler has a full complement of COMS/CEMS instrumentation to monitor stack gas emissions and opacity.

The spreader stoker boiler uses mechanical feeders to distribute coal uniformly over the surface of a moving grate. Introducing the fuel into the furnace and onto the grate results in combustion of coal both on the moving grate as well as in suspension directly above the grate. The amount of fuel burned in suspension depends primarily on fuel size and composition, and airflow velocity. Generally, fuels with finer size distributions, higher volatile matter, and lower moisture contents result in a greater percentage of combustion and corresponding heat release rates in suspension above the bed.

This combustion arrangement produces particulate matter in the form of fly ash and partially burned coal that is entrained in the flue gas. The gas proceeds first through a multi-clone cyclone. The cyclone is capable of collecting up to 70% of the total particulate load. The exhaust then proceeds through the ESP, which captures up to 99.7% of the remaining particulate. The exhaust then passes through an economizer, an ID fan, and an FGD scrubber before exiting the stack.

Operational factors that can affect the amount of PM generated include:

- steam production rate of the boiler
- screen size of the stoker coal
- flue gas velocity
- combustion efficiency

Rationale for Performance Indicators and Ranges

The CAM plan for the boiler was developed using information from EPA Method 5 emission tests conducted from 1993 – 2000 and from corresponding opacities via COMS.

After thorough review of the available stack test information and from process knowledge of the coal combustion process and of stoker boiler performance in particular, the following conclusion could be drawn: opacity is the most useful real-time parameter to estimate real-time PM emissions. Rigorous statistical analyses verified that opacity is the only parameter that has reasonable correlation with PM. Operating rate, flue gas volume, ESP secondary current, and CO emission levels all influence changes in opacity and PM emission rates, but singularly do not statistically correlate with PM emissions.

Two regressions were developed in order to obtain the information necessary for correlating opacity and gr/dscf. The first regression predicts exhaust gas flow rate in dry standard cubic feet per minute (DSCFM) based on the steam production rate. A linear regression is used with a data set of n = 13, gathered from stack tests conducted over a wide range of steam rates:

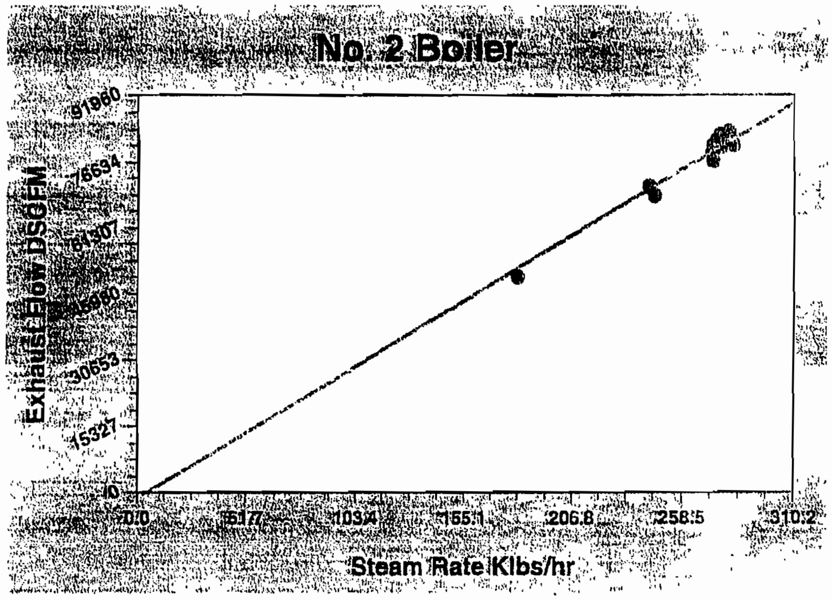
12-23-2005 031083

Steam rate vs DSCFM

Linear Fit: y=a+bx

Coefficient Data:

a =	-1242.2
b =	295.0
r =	0.996
S =	2015.5
Coeff of Var =	3%



Using the regression, the exhaust gas rate in DSCFM can be estimated for any steam rate. For example, with x = 300 thousand pound per hour (Klb/hr) steam rate (100% capacity):

$$y = a + bx$$
$$y = -1242.2 + 295.0 * 300$$
$$y = 87258 \text{ DSCFM}$$

The DSCFM number is important, as it allows one to back-calculate the maximum allowable grains per dry standard cubic feet per minute (gr/dscf) emission for a given steam rate (heat input in MMBTU/hr).

At the permitted emission rate of 0.10 lb/MMBTU and with UIN-15 Boiler No. 2 rated at 358.5 MMBTU/hr @ 300 Klb/hr steam production:

$$0.10 \text{ lb/MMBTU} * 358.5 \text{ MMBTU/hr} = 35.85 \text{ lb/hr PM mass emission limit}$$

Converting lb/hr into gr/min:

$$35.85 \text{ lb/hr} * 7000 \text{ gr/lb} \div 60\text{min/hr} = 4182.5 \text{ gr/min}$$

Using the estimated flow rate from the regression, the maximum PM emission rate in gr/dscf can be estimated:

$$4182.5 \text{ gr/min} \div 87258 \text{ DSCFM} = 0.0479 \text{ gr/dscf}$$

To account for inherent error in the flow rate regression, the coefficient of variation of 3% is applied to the emission, resulting in the most conservative estimate:

$$4182.5 \text{ gr/min} \div (87258 \text{ DSCFM}*1.03) = \mathbf{0.0465 \text{ gr/DSCF}}$$

This defines the ma. .m allowable *mass* emission at the n .ium steam rate (35.85 lb/hr). It also defines the maximum emission on a *rate* basis (0.10 lb/MMBTU) throughout the entire boiler operating range.

The boiler firing rate is considered proportional to the steam rate, and therefore proportional to the air flow rate. Three examples of various steam rates indicate that essentially the same PM concentration applies in all three cases:

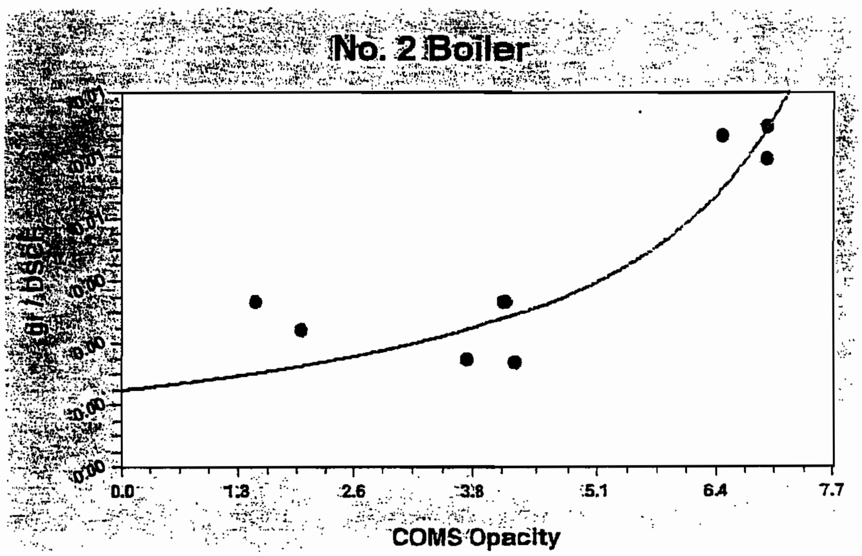
Steam Rate	Steam Klbs/hr	DSCFM	MMBTU/hr	gr/DSCF@0.10 lb/MMBTU
100%	300	87258	358.5	0.0465
75%	225	65133	268.9	0.0468
50%	150	43008	179.3	0.0472

The second regression predicts actual PM emission based on opacity. A linear regression is used with a data set of n = 12:

Opacity vs gr/DSCF

Quadratic Fit:
y=a+bx+cx^2
Coefficient Data:

a =	0.001436
b =	0.00020
c =	0.000107
r =	0.900
S =	0.0014
Coeff. of Var.	29%



Solving for x (opacity), one can predict the maximum opacity allowable to not exceed the 0.0465 gr/dscf limit:

y = a + bx + cx^2

0.0465 = 0.001436 + 0.00020***19.6** + 0.000107***19.6**^2

Again to account for inherent error in the emission regression, the coefficient of variation of 29% is applied to the opacity to result in the most conservative estimate:

19.6 ÷ 1.29 = **15.2% opacity**

CAM Plan Application
Application of this CAM plan is as follows - if a rolling 3-hour average opacity exceeds 15.2% at any boiler operating rate, adjustments to boiler operation are necessary. These adjustments can range from optimizing the fuel/air ratio, adjusting coal feeders, increasing precipitator power, etc.

Appendix D

Portable Analyzer Protocol

STATE OF WYOMING AIR QUALITY DIVISION
PORTABLE ANALYZER MONITORING PROTOCOL

Determination of Nitrogen Oxides, Carbon Monoxide and Oxygen Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers

WYOMING DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION
122 West 25th Street
Cheyenne, Wyoming 82002

April 21, 1999
Revised January 25, 2006

Approved By: ____________________
Dan Olson
Administrator

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1. APPLICABILITY AND PRINCIPLE

1.1 Applicability. This method is applicable to the determination of nitrogen oxides (NO and NO_2), carbon monoxide (CO), and oxygen (O_2) concentrations in controlled and uncontrolled emissions from natural gas-fired reciprocating engines, combustion turbines, boilers, and process heaters using portable analyzers with electrochemical cells. The use of reference method equivalent analyzers is acceptable provided the appropriate reference method procedures in 40 CFR 60, Appendix A are used. Due to the inherent cross sensitivities of the electrochemical cells, this method is not applicable to other pollutants.

1.2 Principle. A gas sample is continuously extracted from a stack and conveyed to a portable analyzer for determination of NO, NO_2, CO, and O_2 gas concentrations using electrochemical cells. Analyzer design specifications, performance specifications, and test procedures are provided to ensure reliable data. Additions to or modifications of vendor-supplied analyzers (e.g. heated sample line, flow meters, etc.) may be required to meet the design specifications of this test method.

2. RANGE AND SENSITIVITY

2.1 Analytical Range. The analytical range for each gas component is determined by the electrochemical cell design. A portion of the analytical range is selected to be the nominal range by choosing a span gas concentration near the flue gas concentrations or permitted emission level in accordance with Sections 2.1.1, 2.1.2 and 2.1.3.

2.1.1 CO and NO Span Gases. Choose a span gas concentration such that the average stack gas reading for each test is greater than 25 percent of the span gas concentration. Alternatively, choose the span gas such that it is not greater than 3.33 times the concentration equivalent to the emission standard. If concentration results exceed 125 percent of the span gas at any time during the test, then the test for that pollutant is invalid.

2.1.2 NO_2 Span Gas. Choose a span gas concentration such that the average stack gas reading for each test is greater than 25 percent of the span gas concentration. Alternatively, choose the span gas concentration such that it is not greater than the ppm concentration value of the NO span gas. The tester should be aware NO_2 cells are generally designed to measure much lower concentrations than NO cells and the span gas should be chosen accordingly. If concentration results exceed 125 percent of the span gas at any time during the test, then the test for that pollutant is invalid.

2.1.3 O_2 Span Gas. The O_2 span gas shall be dry ambient air at 20.9% O_2.

3. DEFINITIONS

3.1 Measurement System. The total equipment required for the determination of gas concentration. The measurement system consists of the following major subsystems:

3.1.1 Sample Interface. That portion of a system used for one or more of the following: sample acquisition, sample transport, sample conditioning, or protection of the electrochemical cells from particulate matter and condensed moisture.

3.1.2 External Interference Gas Scrubber. A tube filled with scrubbing agent used to remove interfering compounds upstream of some electrochemical cells.

3.1.3 Electrochemical (EC) Cell. That portion of the system that senses the gas to be measured and generates an output proportional to its concentration. Any cell that uses diffusion-limited oxidation and reduction reactions to produce an electrical potential between a sensing electrode and a counter electrode.

3.1.4 Data Recorder. It is recommended that the analyzers be equipped with a strip chart recorder, computer, or digital recorder for recording measurement data. However, the operator may record the test results manually in accordance with the requirements of Section 7.5.

3.2 Nominal Range. The range of concentrations over which each cell is operated (25 to 125 percent of span gas value). Several nominal ranges may be used for any given cell as long as the linearity and stability check results remain within specification.

3.3 Span Gas. The high level concentration gas chosen for each nominal range.

3.4 Zero Calibration Error. For the NO, NO_2 and CO channels, the absolute value of the difference, expressed as a percent of the span gas, between the gas concentration exhibited by the gas analyzer when a zero level calibration gas is introduced to the analyzer and the known concentration of the zero level calibration gas. For the O_2 channel, the difference, expressed as percent O_2, between the gas concentration exhibited by the gas analyzer when a zero level calibration gas is introduced to the analyzer and the known concentration of the zero level calibration gas.

3.5 Span Calibration Error. For the NO, NO_2 and CO channels, the absolute value of the difference, expressed as a percent of the span gas, between the gas concentration exhibited by the gas analyzer when a span gas is introduced to the analyzer and the known concentration of the span gas. For the O_2 channel, the difference, expressed as percent O_2, between the gas concentration exhibited by the gas analyzer when a span gas is introduced to the analyzer and the known concentration of the span gas.

3.6 Response Time. The amount of time required for the measurement system to display 95 percent of a step change in the NO or CO gas concentration on the data recorder (90 percent of a step change for NO_2).

3.7 Interference Check. A method of quantifying analytical interferences from components in the stack gas other than the analyte.

3.8 Linearity Check. A method of demonstrating the ability of a gas analyzer to respond consistently over a range of gas concentrations.

3.9 Stability Check. A method of demonstrating an electrochemical cell operated over a given nominal range provides a stable response and is not significantly affected by prolonged exposure to the analyte.

3.10 Stability Time. As determined during the stability check; the elapsed time from the start of the gas injection until a stable reading has been achieved.

3.11 Initial NO Cell Temperature. The temperature of the NO cell during the pretest calibration error check. Since the NO cell can experience significant zero drift with cell temperature changes in some situations, the cell temperature must be monitored if the analyzer does not display negative concentration results. Alternatively, manufacturer's documentation may be submitted showing the analyzer incorporates a NO cell temperature control and temperature exceedance warning system.

3.12 Test. The collection of emissions data from a source for an equal amount of time at each sample point and for a minimum of 21 minutes total.

4. MEASUREMENT SYSTEM PERFORMANCE SPECIFICATIONS

4.1 Zero Calibration Error. Less than or equal to ±3 percent of the span gas value for NO, NO_2, and CO channels and less than or equal to ±0.3 percent O_2 for the O_2 channel.

4.2 Span Calibration Error. Less than or equal to ±5 percent of the span gas value for NO, NO_2, and CO channels and less than or equal to ±0.5 percent O_2 for the O_2 channel.

4.3 Interference Response. The CO and NO interference responses must be less than or equal to 5 percent as calculated in accordance with Section 7.7.

4.4 Linearity. For the zero, mid-level, and span gases, the absolute value of the difference, expressed as a percent of the span gas, between the gas value and the analyzer response shall not be greater than 2.5 percent for NO, CO and O_2 cells and not greater than 3.0 percent for NO_2 cells.

4.5 Stability Check Response. The analyzer responses to CO, NO, and NO_2 span gases shall not vary more than 3.0 percent of span gas value over a 30-minute period or more than 2.0 percent of the span gas value over a 15-minute period.

4.6 CO Measurement, Hydrogen (H_2) Compensation. It is recommended that CO measurements be performed using a hydrogen-compensated EC cell since CO-measuring EC cells can experience significant reaction to the presence of H_2 in the gas stream. Sampling systems equipped with a scrubbing agent prior to the CO cell to remove H_2 interferent gases may also be used.

5. APPARATUS AND REAGENTS

5.1 Measurement System. Use any measurement system that meets the performance and design specifications in Sections 4 and 5 of this method. The sampling system shall maintain the gas sample at a temperature above the dew point up to the moisture removal system. The sample conditioning system shall be designed so there are no entrained water droplets in the gas sample when it contacts the electrochemical cells. A schematic of an acceptable measurement system is shown in Figure 1. The essential components of the measurement system are described below:

5.1.1 Sample Probe. Glass, stainless steel, or other nonreactive material, of sufficient length to sample per the requirements of Section 7. If necessary to prevent condensation, the sampling probe shall be heated.

5.1.2 Heated Sample Line. Heated (sufficient to prevent condensation) nonreactive tubing such as teflon, stainless steel, glass, etc. to transport the sample gas to the moisture removal system. (Includes any particulate filters prior to the moisture removal system.)

5.1.3 Sample Transport Lines. Nonreactive tubing such as teflon, stainless steel, glass, etc. to transport the sample from the moisture removal system to the sample pump, sample flow rate control, and electrochemical cells.

5.1.4 Calibration Assembly. A tee fitting to attach to the probe tip or where the probe attaches to the sample line for introducing calibration gases at ambient pressure during the calibration error checks. The vented end of the tee should have a flow indicator to ensure sufficient calibration gas flow. Alternatively use any other method that introduces calibration gases at the probe at atmospheric pressure.

5.1.5 Moisture Removal System. A chilled condenser or similar device (e.g., permeation dryer) to remove condensate continuously from the sample gas while maintaining minimal contact between the condensate and the sample gas.

5.1.6 Particulate Filter. Filters at the probe or the inlet or outlet of the moisture removal system and inlet of the analyzer may be used to prevent accumulation of particulate material in the measurement system and extend the useful life of the components. All filters shall be fabricated of materials that are nonreactive to the gas being sampled.

5.1.7 Sample Pump. A leak-free pump to pull the sample gas through the system at a flow rate sufficient to minimize the response time of the measurement system. The pump may be constructed of any material that is nonreactive to the gas being sampled.

5.1.8 Sample Flow Rate Control. A sample flow rate control valve and rotameter, or equivalent, to maintain a constant sampling rate within 10 percent during sampling and calibration error checks. The components shall be fabricated of materials that are nonreactive to the gas being sampled.

5.1.9 Gas Analyzer. A device containing electrochemical cells to determine the NO, NO_2, CO, and O_2 concentrations in the sample gas stream and, if necessary, to correct for interference effects. The analyzer shall meet the applicable performance specifications of Section 4. A means of controlling the analyzer flow rate and a device for determining proper sample flow rate (e.g., precision rotameter, pressure gauge downstream of all flow controls, etc.) shall be provided at the analyzer. (Note: Housing the analyzer in a clean, thermally-stable, vibration-free environment will minimize drift in the analyzer calibration, but this is not a requirement of the method.)

5.1.10 Data Recorder. A strip chart recorder, computer, or digital recorder, for recording measurement data. The data recorder resolution (i.e., readability) shall be at least 1 ppm for CO, NO, and NO_2; 0.1 percent O_2 for O_2; and one degree (C or F) for temperature.

5.1.11 External Interference Gas Scrubber. Used by some analyzers to remove interfering compounds upstream of a CO electrochemical cell. The scrubbing agent should be visible and should have a means of determining when the agent is exhausted (e.g., color indication).

5.1.12 NO Cell Temperature Indicator. A thermocouple, thermistor, or other device must be used to monitor the temperature of the NO electrochemical cell. The temperature may be monitored at the surface of the cell, within the cell or in the cell compartment. Alternatively, manufacturer's documentation may be submitted showing the analyzer incorporates a NO cell temperature control and temperature exceedance warning system.

5.1.13 Dilution Systems. The use of dilution systems will be allowed with prior approval of the Air Quality Division.

5.2 Calibration Gases. The CO, NO, and NO_2 calibration gases for the gas analyzer shall be CO in nitrogen or CO in nitrogen and O_2, NO in nitrogen, and NO_2 in air or nitrogen. The mid-level O_2 gas shall be O_2 in nitrogen.

5.2.1 Span Gases. Used for calibration error, linearity, and interference checks of each nominal range of each cell. Select concentrations according to procedures in Section 2.1. Clean dry air may be used as the span gas for the O_2 cell as specified in Section 2.1.3.

5.2.2 Mid-Level Gases. Select concentrations that are 40-60 percent of the span gas concentrations.

5.2.3 Zero Gas. Concentration of less than 0.25 percent of the span gas for each component. Ambient air may be used in a well ventilated area for the CO, NO, and NO_2 zero gases.

6. MEASUREMENT SYSTEM PERFORMANCE CHECK PROCEDURES. Perform the following procedures before the measurement of emissions under Section 7.

6.1 Calibration Gas Concentration Certification. For the mid-level and span cylinder gases, use calibration gases certified according to EPA Protocol 1 procedures. Calibration gases must meet the criteria under 40 CFR 60, Appendix F, Section 5.1.2 (3). Expired Protocol 1 gases may be recertified using the applicable reference methods.

6.2 Linearity Check. Conduct the following procedure once for each nominal range to be used on each electrochemical cell (NO, NO_2, CO, and O_2). After a linearity check is completed, it remains valid for five consecutive calendar days. After the five calendar day period has elapsed, the linearity check must be reaccomplished. Additionally, reaccomplish the linearity check if the cell is replaced. (If the stack NO_2 concentration is less than 5% of the stack NO concentration as determined using the emission test procedures under Section 7, the NO_2 linearity check is not required. However, the NO_2 cell shall be calibrated in accordance with the manufacturer's instructions, the pretest calibration error check and post test calibration calibration error check shall be conducted in accordance with Section 7, and the test results shall be added to the NO test values to obtain a total NO_X concentration.)

6.2.1 Linearity Check Gases. For each cell obtain the following gases: zero (0-0.25 percent of nominal range), mid-level (40-60 percent of span gas concentration), and span gas (selected according to Section 2.1).

6.2.2 Linearity Check Procedure. If the analyzer uses an external interference gas scrubber with a color indicator, using the analyzer manufacturer's recommended procedure, verify the scrubbing agent is not depleted. After calibrating the analyzer with zero and span gases, inject the zero, mid-level, and span gases appropriate for each nominal range to be used on each cell. Gases need not be injected through the entire sample handling system. Purge the analyzer briefly with ambient air between gas injections. For each gas injection, verify the flow rate is constant and the analyzer responses have stabilized before recording the responses on Form A.

6.3 Interference Check. A CO cell response to the NO and NO_2 span gases or an NO cell response to the NO_2 span gas during the linearity check may indicate interferences. If these cell responses are observed during the linearity check, it may be desirable to quantify the CO cell response to the NO and NO_2 span gases and the NO cell response to the NO_2 span gas during the linearity check and use estimated stack gas CO, NO and NO_2 concentrations to evaluate whether or not the portable analyzer will meet the post test interference check requirements of Section 7.7. This evaluation using the linearity check data is optional. However, the interference checks under Section 7.7 are manditory for each test.

6.4 Stability Check. Conduct the following procedure once for the maximum nominal range to be used on each electrochemical cell (NO, NO_2 and CO). After a stability check is completed, it remains valid for five consecutive calendar days. After the five calendar day period has elapsed, the stability check must be reaccomplished. Additionally, reaccomplish the stability check if the cell is replaced or if a cell is exposed to gas concentrations greater than 125 percent of the highest span gas concentration. (If the stack NO_2 concentration is less than 5% of the stack NO concentration as determined using the emission test procedures under Section 7, the NO_2 stability check is not required. However, the NO_2 cell shall be calibrated in accordance with the manufacturer's instructions, the pretest calibration error check and post test calibration calibration error check shall be conducted in accordance with Section 7, and the test results shall be added to the NO test values to obtain a total NO_X concentration.)

6.4.1 Stability Check Procedure. Inject the span gas for the maximum nominal range to be used during the emission testing into the analyzer and record the analyzer response at least once per minute until the conclusion of the stability check. One-minute average values may be used instead of instantaneous readings. After the analyzer response has stabilized, continue to flow the span gas for at least a 30-minute stability check period. Make no adjustments to the analyzer during the stability check except to maintain constant flow. Record the stability time as the number of minutes elapsed between the start of the gas injection and the start of the 30-minute stability check period. As an alternative, if the concentration reaches a peak value within five minutes, you may choose to record the data for at least a 15-minute stability check period following the peak.

6.4.2 Stability Check Calculations. Determine the highest and lowest concentrations recorded during the 30-minute period and record the results on Form B. The absolute value of the difference between the maximum and minimum values recorded during the 30-minute period must be less than 3.0 percent of the span gas concentration. Alternatively, record stability check data in the same manner for the 15-minute period following the peak concentration. The difference between the maximum and minimum values for the 15-minute period must be less than 2.0 percent of the span gas concentration.

7. EMISSION TEST PROCEDURES. Prior to performing the following emission test procedures, calibrate/challenge all electrochemical cells in the analyzer in accordance with the manufacturer's instructions.

7.1 Selection of Sampling Site and Sampling Points.

7.1.1 Reciprocating Engines. Select a sampling site located at least two stack diameters downstream of any disturbance (e.g., turbocharger exhaust, crossover junction, or recirculation take-offs) and one half stack diameter upstream of the gas discharge to the atmosphere. Use a sampling location at a single point near the center of the duct.

7.1.2 Combustion Turbines. Select a sampling site and sample points according to the procedures in 40 CFR 60, Appendix A, Method 20. Alternatively, the tester may choose an alternative sampling location and/or sample from a single point in the center of the duct if previous test data demonstrate the stack gas concentrations of CO, NO_X, and O_2 do not vary significantly across the duct diameter.

7.1.3 Boilers/Process Heaters. Select a sampling site located at least two stack diameters downstream of any disturbance and one half stack diameter upstream of the gas discharge to the atmosphere. Use a sampling location at a single point near the center of the duct.

7.2 Warm Up Period. Assemble the sampling system and allow the analyzer and sample interface to warm up and adjust to ambient temperature at the location where the stack measurements will take place.

7.3 Pretest Calibration Error Check. Conduct a zero and span calibration error check before testing each new source. Conduct the calibration error check near the sampling location just prior to the start of an emissions test. Keep the analyzer in the same location until the post test calibration error check is conducted.

7.3.1 Scrubber Inspection. For analyzers that use an external interference gas scrubber tube, inspect the condition of the scrubbing agent and ensure it will not be exhausted during sampling. If scrubbing agents are recommended by the manufacturer, they should be in place during all sampling, calibration and performance checks.

7.3.2 Zero and Span Procedures. Inject the zero and span gases using the calibration assembly. Ensure the calibration gases flow through all parts of the sample interface. During this check, make no adjustments to the system except those necessary to achieve the correct calibration gas flow rate at the analyzer. Set the analyzer flow rate to the value recommended by the analyzer manufacturer. Allow each reading to stabilize before recording the result on Form C. The time allowed for the span gas to stabilize shall be no less than the stability time noted during the stability check. After achieving a stable response, disconnect the gas and briefly purge with ambient air.

7.3.3 Response Time Determination. Determine the NO and CO response times by observing the time required to respond to 95 percent of a step change in the analyzer response for both the zero and span gases. Note the longer of the two times as the response time. For the NO_2 span gas record the time required to respond to 90 percent of a step change.

7.3.4 Failed Pretest Calibration Error Check. If the zero and span calibration error check results are not within the specifications in Section 4, take corrective action and repeat the calibration error check until acceptable performance is achieved.

7.4 NO Cell Temperature Monitoring. Record the initial NO cell temperature during the pretest calibration error check on Form C and monitor and record the temperature regularly (at least once each 7 minutes) during the sample collection period on Form D. If at any time during sampling, the NO cell temperature is 85 degrees F or greater and has increased or decreased by more than 5 degrees F since the pretest calibration, stop sampling immediately and conduct a post test calibration error check per Section 7.6, re-zero the analyzer, and then conduct another pretest calibration error check per Section 7.3 before continuing. (It is recommended that testing be discontinued if the NO cell exceeds 85 degrees F since the design characteristics of the NO cell indicate a significant measurement error can occur as the temperature of the NO cell increases above this temperature. From a review of available data, these errors appear to result in a positive bias of the test results.)

Alternatively, manufacturer's documentation may be submitted showing the analyzer is configured with an automatic temperature control system to maintain the cell temperature below 85 degrees F (30 degrees centigrade) and provides automatic temperature reporting any time this temperature is exceeded. If automatic temperature control/exceedance reporting is used, test data collected when the NO cell temperature exceeds 85 degrees F is invalid.

7.5 Sample Collection. Position the sampling probe at the first sample point and begin sampling at the same rate used during the calibration error check. Maintain constant rate sampling (± 10 percent of the analyzer flow rate value used in Section 7.3.2) during the entire test. Sample for an equal period of time at each sample point. Sample the stack gas for at least twice the response time or the period of the stability time, whichever is greater, before collecting test data at each sample point. A 21 minute period shall be considered a test for each source. When sampling combustion turbines per Section 7.1.2, collect test data as required to meet the requirements of 40 CFR 60, Appendix A, Method 20. Data collection should be performed for an equal amount of time at each sample point and for a minimum of 21 minutes total. The concentration data must be recorded either (1) at least once each minute, or (2) as a block average for the test using values sampled at least once each minute. Do not break any seals in the sample handling system until after the post test calibration error check (this includes opening the moisture removal system to drain condensate).

7.6 Post Test Calibration Error Check. Immediately after the test, conduct a zero and span calibration error check using the procedure in Section 7.3. Conduct the calibration error check at the sampling location. Make no changes to the sampling system or analyzer calibration until all of the calibration error check results have been recorded. If the zero or span calibration error exceeds the specifications in Section 4, then all test data collected since the previous calibration error check are invalid. If the sampling system is disassembled or the analyzer calibration is adjusted, repeat the pretest calibration error check before conducting the next test.

7.7 Interference Check. Use the post test calibration error check results and average emission concentrations for the test to calculate interference responses (I_{NO} and I_{CO}) for the CO and NO cells. If an interference response exceeds 5 percent, all emission test results since the last successful interference test for that compound are invalid.

7.7.1 CO Interference Response.

$$I_{CO} = [(\frac{R_{CO\text{-}NO}}{C_{NOG}})(\frac{C_{NOS}}{C_{COS}}) + (\frac{R_{CO\text{-}NO_2}}{C_{NO_2G}})(\frac{C_{NO_2S}}{C_{COS}})]x100$$

where:

I_{CO} = CO interference response (percent)

$R_{CO\text{-}NO}$ = CO response to NO span gas (ppm CO)

C_{NOG} = concentration of NO span gas (ppm NO)

C_{NOS} = concentration of NO in stack gas (ppm NO)

C_{COS} = concentration of CO in stack gas (ppm CO)

$R_{CO\text{-}NO2}$ = CO response to NO_2 span gas (ppm CO)

C_{NO2G} = concentration of NO_2 span gas (ppm NO_2)

C_{NO2S} = concentration of NO_2 in stack gas (ppm NO_2)

7.7.2 NO Interference Response.

$$I_{NO} = (\frac{R_{NO\text{-}NO_2}}{C_{NO_2G}})(\frac{C_{NO_2S}}{C_{NO_XS}})x100$$

where:

I_{NO} = NO interference response (percent)

$R_{NO\text{-}NO2}$ = NO response to NO_2 span gas (ppm NO)

C_{NO2G} = concentration of NO_2 span gas (ppm NO_2)

C_{NO2S} = concentration of NO_2 in stack gas (ppm NO_2)

C_{NOxS} = concentration of NO_X in stack gas (ppm NO_X)

7.8 Re-Zero. At least once every three hours, recalibrate the analyzer at the zero level according to the manufacturer's instructions and conduct a pretest calibration error check before resuming sampling. If the analyzer is capable of reporting negative concentration data (at least 5 percent of the span gas below zero), then the tester is not required to re-zero the analyzer.

8. DATA COLLECTION. This section summarizes the data collection requirements for this protocol.

8.1 Linearity Check Data. Using Form A, record the analyzer responses in ppm NO, NO_2, and CO, and percent O_2 for the zero, mid-level, and span gases injected during the linearity check under Section 6.2.2. To evaluate any interferences, record the analyzer responses in ppm CO to the NO and NO_2 span gases and the analyzer response in ppm NO to the NO_2 span gas. Calculate the CO and NO interference responses using the equations under Sections 7.7.1 and 7.7.2, respectively, and estimated stack gas CO, NO and NO_2 concentrations.

8.2 Stability Check Data. Record the analyzer response at least once per minute during the stability check under Section 6.4.1. Use Form B for each pollutant (NO, NO_2, and CO). One-minute average values may be used instead of instantaneous readings. Record the stability time as the number of minutes elapsed between the start of the gas injection and the start of the 30-minute stability check period. If the concentration reaches a peak value within five minutes of the gas injection, you may choose to record the data for at least a 15-minute stability check period following the peak. Use the information recorded to determine the analyzer stability under Section 6.4.2.

8.3 Pretest Calibration Error Check Data. On Form C, record the analyzer responses to the zero and span gases for NO, NO_2, CO, and O_2 injected prior to testing each new source. Record the calibration zero and span gas concentrations for NO, NO_2, CO, and O_2. For NO, NO_2 and CO, record the absolute difference between the analyzer response and the calibration gas concentration, divide by the span gas concentration, and multiply by 100 to obtain the percent of span. For O_2, record the absolute value of the difference between the analyzer response and the O_2 calibration gas concentration. Record whether the calibration is valid by comparing the percent of span or difference between the calibration gas concentration and analyzer O_2 response, as applicable, with the specifications under Section 4.1 for the zero calibrations and Section 4.2 for the span calibrations. Record the response times for the NO, CO, and NO_2 zero and span gases as described under Section 7.3.3. Select the longer of the two times for each pollutant as the response time for that pollutant. Record the NO cell temperature during the pretest calibration.

8.4 Test Data. On Form D-1, D-2, or D-3, record the source operating parameters during the test. Record the test start and end times. Record the NO cell temperature after one third of the test (e.g., after seven minutes) and after two thirds of the test (e.g., after 14 minutes). From the analyzer responses recorded each minute during the test, obtain the average flue gas concentration of each pollutant. These are the uncorrected test results.

8.5 Post Test Calibration Error Check Data. On Form C, record the analyzer responses to the zero and span gases for NO, NO_2, CO, and O_2 injected immediately after the test. To evaluate any interferences, record the analyzer responses in ppm CO to the NO and NO_2 span gases and the analyzer response in ppm NO to the NO_2 span gas. Record the calibration zero and span gas concentrations for NO, NO_2, CO, and O_2. For NO, NO_2 and CO, record the absolute difference between the analyzer response and the calibration gas concentration, divide by the span gas concentration, and multiply by 100 to obtain the percent of span. For O_2, record the absolute value of the difference between the analyzer response and the O_2 calibration gas concentration. Record whether the calibration is valid by comparing the percent of span or difference between the calibration gas concentration and analyzer O_2 response, as applicable, with the specifications under Section 4.1 for the zero calibrations and Section 4.2 for the span calibrations. (If the pretest and post test calibration error check results are not within the limits specified in Sections 4.1 and 4.2, data collected during the test is invalid and the test must be repeated.) Record the NO cell temperature during the post test calibration. Calculate the average of the monitor readings during the pretest and post test calibration error checks for the zero and span gases for NO, NO_2, CO, and O_2. The pretest and post test calibration error check results are used to make the calibration corrections under Section 9.1. Calculate the CO and NO interference responses using the equations under Sections 7.7.1 and 7.7.2, respectively and measured stack gas CO, NO and NO_2 concentrations.

8.6 Corrected Test Results. Correct the test results using the equation under Section 9.1. Add the corrected NO and NO_2 concentrations together to obtain the corrected NO_X concentration. Calculate the emission rates using the equations under Section 10 for comparison with the emission limits. Record the results on Form D-1, D-2, or D-3. Sign the certification regarding the accuracy and representation of the emissions from the source.

9. CALIBRATION CORRECTIONS

9.1 Emission Data Corrections. Emissions data shall be corrected for a test using the following equation. (Note: If the pretest and post test calibration error check results are not within the limits specified in Sections 4.1 and 4.2, the test results are invalid and the test must be repeated.)

$$C_{Corrected} = (C_R - C_O)\frac{C_{MA}}{C_M - C_O}$$

where: $C_{Corrected}$ = corrected flue gas concentration (ppm)
C_R = flue gas concentration indicated by gas analyzer (ppm)
C_o = average of pretest and post test analyzer readings during the zero checks (ppm)
C_M = average of pretest and post test analyzer readings during the span checks (ppm)
C_{MA} = actual concentration of span gas (ppm)

10. EMISSION CALCULATIONS

10.1 Emission Calculations for Reciprocating Engines and Combustion Turbines. Emissions shall be calculated and reported in units of the allowable emission limit as specified in the permit. The allowable may be stated in pounds per hour (lb/hr), grams per horsepower hour (gm/hp-hr), or both. EPA Reference Method 19 shall be used as the basis for calculating the emissions. As an alternative, EPA Reference Methods 1-4 may be used to obtain a stack volumetric flow rate.

10.1.1 Reciprocating Engines and Combustion Turbines Above 500 Horsepower. All reciprocating engines and combustion turbines above 500 horsepower (site-rated) should be equipped with fuel flow meters for measuring fuel consumption during the portable analyzer test.

The fuel meter shall be maintained and calibrated according to the manufacturer's recommendations. Records of all maintenance and calibrations shall be kept for five years. Reciprocating engines above 500 horsepower which are not equipped with fuel flow meters may use the site-rated horsepower and default specific fuel consumption factors, based on the higher heating value of the fuel, of 9,400 Btu/hp-hr for 4-cycle engines (controlled and uncontrolled) and 2-cycle lean burn engines and 11,000 Btu/hp-hr for 2-cycle uncontrolled (non-lean burn) engines to calculate emission rates. Emissions shall be calculated using the following methods.

10.1.1.1 Reciprocating Engines and Combustion Turbines Equipped with Fuel Meters. EPA Reference Method 19 and heat input per hour (MMBtu/hr) shall be used to calculate a pound per hour emission rate. Heat input per hour shall be based on the average hourly fuel usage rate during the test and the higher heating value of the fuel consumed. The emission rates shall be calculated using the following equations.

$$lb/hr\ NO_X = (ppm\ NO_{X_{corrected}})(1.19x10^{-7})(F\ Factor_{Note1})\left(\frac{20.9}{20.9 - O_2\%_{corrected}}\right)(Heat\ Input\ Per\ Hour_{Note2})$$

$$lb/hr\ CO = (ppm\ CO_{corrected})(7.27x10^{-8})(F\ Factor_{Note1})\left(\frac{20.9}{20.9 - O_2\%_{corrected}}\right)(Heat\ Input\ Per\ Hour_{Note2})$$

Note 1 - Use 8710 dscf/MMBtu unless calculated based on actual fuel gas composition and higher heating value of the fuel.

Note 2 - Heat input per hour (MMBtu/hr) shall be based on the average hourly fuel usage during the test and the higher heating value of the fuel consumed.

If the reciprocating engine or combustion turbine horsepower can be derived from operating conditions during the portable analyzer test, this derived horsepower should be used to calculate a gram per horsepower hour emission rate using the following equations. Information showing the derivation of the horsepower shall be provided with the test results.

$$gm/hp - hr\ CO = \frac{(lb/hr\ CO)(454)}{(Tested\ Horsepower_{Note\ 1})}$$

$$gm/hp - hr\ NO_X = \frac{(lb/hr\ NO_X)(454)}{(Tested\ Horsepower_{Note\ 1})}$$

Note 1 - Horsepower determined during the test.

If the reciprocating engine horsepower during the time of testing cannot determined from the operating data, the operating horsepower for the time of the test shall be calculated based on the heat input per hour during the test and the default values shown below for specific fuel consumption based on the higher heating value of the fuel. Heat input per hour (MMBtu/hr) shall be calculated based on the average hourly fuel usage during the test and the higher heating value of the fuel consumed. For 4-cycle engines (controlled and uncontrolled) and 2-cycle lean burn engines, use a default specific fuel consumption of 9,400 Btu/hp-hr. For 2-cycle uncontrolled (non-lean burn) engines, use a default specific fuel consumption of 11,000 Btu/hp-hr. Calculate the gram per horsepower hour emission rates using the following equations.

$$Engine\ Horsepower = \frac{(Heat\ Input\ Per\ Hour_{Note\ 1})(10^6)}{(Specific\ Fuel\ Consumption_{Note\ 2})}$$

$$gm/hp - hr\ NO_X = \frac{(lb/hr\ NO_X)(454)}{(Engine\ Horsepower)}$$

$$gm/hp - hr\ CO = \frac{(lb/hr\ CO)(454)}{(Engine\ Horsepower)}$$

Note 1 - Heat input per hour (MMBtu/hr) shall be based on the average hourly fuel usage during the test and the higher heating value of the fuel consumed.

Note 2 - Default Specific Fuel Consumption (Btu/hp-hr) shall be as defined above for the particular type of engine tested.

If the combustion turbine horsepower cannot be calculated during the testing, the emissions shall be reported in terms of concentration (ppm by volume, dry basis) corrected to 15 percent O_2. Compliance with the concentrations corrected to 15 percent O_2 as submitted in the air quality permit application and/or set as an allowable in the permit will demonstrate compliance with the gm/hp-hr allowable. Use the following equations to correct the concentrations to 15 percent O_2.

$$ppm\ NO_{X_{@15\%O_2}} = ppm\ NO_{X_{corrected}} \left(\frac{5.9}{20.9 - O_2\%_{corrected}} \right)$$

$$ppm\ CO_{@15\%O_2} = ppm\ CO_{corrected} \left(\frac{5.9}{20.9 - O_2\%_{corrected}} \right)$$

10.1.1.2 Reciprocating Engines Above 500 Horsepower Not Equipped with Fuel Meters. If reciprocating engines above 500 horsepower (site-rated) are not equipped with fuel flow meters during the test, emissions shall be calculated using the site-rated horsepower and default specific fuel consumption factors, based on the higher heating value of the fuel, of 9,400 Btu/hp-hr for 4-cycle engines (controlled and uncontrolled) and 2-cycle lean burn engines and 11,000 Btu/hp-hr for 2-cycle uncontrolled (non-lean burn) engines. The following equations shall be used to calculate emissions.

$$gm/hp - hr\ NO_X = (ppm\ NO_{X\ corrected})(1.19x10^{-7})(F\ Factor_{Note\ 1})(\frac{20.9}{20.9 - O_2\%_{corrected}})$$
$$(Specific\ Fuel\ Consumption_{Note\ 2})(10^{-6})(454)$$

$$lb/hr\ NO_X = \frac{(gm/hp - hr\ NO_X)(Engine\ Horsepower_{Note\ 3})}{454}$$

$$gm/hp - hr\ CO = (ppm\ CO_{corrected})(7.27x10^{-8})(F\ Factor_{Note\ 1})(\frac{20.9}{20.9 - O_2\%_{corrected}})$$
$$(Specific\ Fuel\ Consumption_{Note\ 2})(10^{-6})(454)$$

$$lb/hr\ CO = \frac{(gm/hp - hr\ CO)(Engine\ Horsepower_{Note\ 3})}{454}$$

Note 1 - Use 8710 dscf/MMBtu unless calculated based on actual fuel gas composition and higher heating value of the fuel.

Note 2 - Default Specific Fuel Consumption (Btu/hp-hr) shall be as defined above for the particular type of engine tested.

Note 3 - Site-rated engine horsepower.

10.1.2 Reciprocating Engines Below 500 Horsepower. Reciprocating engines below 500 horsepower may calculate emission rates using the derived horsepower for the operating conditions during the portable analyzer test (either from engine parameter measurements or calculated from compressor operating parameters) and the manufacturer's specific fuel consumption based on the higher heating value of the fuel consumed during the test. Information showing the derivation of the engine operating horsepower and manufacturer's specific fuel consumption shall be provided with the test results. The following equations shall be used to calculate emission rates.

$$gm/hp - hr\ NO_X = \frac{(ppm\ NO_{X\ corrected})(1.19x10^{-7})(F\ Factor_{Note\ 1})(\frac{20.9}{20.9 - O_2\%_{corrected}})}{(Specific\ Fuel\ Consumption_{Note\ 2})(10^{-6})(454)}$$

$$gm/hp - hr\ CO = \frac{(ppm\ CO_{corrected})(7.27x10^{-8})(F\ Factor_{Note\ 1})(\frac{20.9}{20.9 - O_2\%_{corrected}})}{(Specific\ Fuel\ Consumption_{Note\ 2})(10^{-6})(454)}$$

Note 1 - Use 8710 dscf/MMBtu unless calculated based on actual fuel gas composition and the higher heating value of the fuel.

Note 2 - Use manufacturer's specific fuel consumption based on the higher heating value of the fuel and include manufacturer's data with the test results. If the manufacturer reports the specific fuel consumption based on the lower heating value of the fuel, multiply by 1.11 to obtain the specific fuel consumption based on the higher heating value of the fuel.

Pound per hour emission rates shall be calculated using the gram per horsepower hour emission rates and the engine horsepower derived from engine or compressor operating parameter data. If engine horsepower data is not available, site-rated horsepower shall be used to calculate pound

$$lb/hr\ NO_X = \frac{(gm/hp - hr\ NO_X)(Engine\ Horsepower_{Note\ 1})}{(454)}$$

$$lb/hr\ CO = \frac{(gm/hp - hr\ CO)(Engine\ Horsepower_{Note\ 1})}{(454)}$$

per hour emissions. The following equations shall be used to calculate emission rates.

Note 1 - Use derived operating horsepower and include derivation method/calculations with the test results. If a derived horsepower is not available or cannot be obtained, use site-rated horsepower.

10.2 Emission Calculations for Heaters/Boilers. For heaters and boilers, pound per million Btu (lb/MMBtu) emission rates shall be calculated based on EPA Reference Method 19. The pound per million Btu emission rates shall be converted to pound per hour emission rates using heat input per hour (MMBtu/hr). The heat input per hour shall be calculated using the average hourly fuel usage rate during test and the higher heating value of the fuel consumed or the permitted maximum heat input per hour for the boiler or heater. If a fuel meter is used to obtain heat input per hour data, the fuel meter shall be maintained and calibrated according to the manufacturer's recommendations. Records of all maintenance and calibrations shall be kept for five years. As an alternative, EPA Reference Methods 1-4 may be used to obtain a stack volumetric flow rate. The following equations shall be used to calculate emission rates.

$$lb/MMBtu\ NO_X = (ppm\ NO_{X\ corrected})(1.19x10^{-7})(F\ Factor_{Note\ 1})(\frac{20.9}{20.9 - O_2\%_{corrected}})$$

$$lb/MMBtu\ CO = (ppm\ CO_{corrected})(7.27x10^{-8})(F\ Factor_{Note\ 1})(\frac{20.9}{20.9 - O_2\%_{corrected}})$$

$$lb/hr\ NO_X = (lb/MMBtu\ NO_X)(Heat\ Input_{Note\ 2})$$

$$lb/hr\ CO = (lb/MMBtu\ CO)(Heat\ Input_{Note\ 2})$$

Note 1 - Use 8710 dscf/MMBtu unless calculated based on actual fuel gas composition and the higher heating value of the fuel.

Note 2 - Heat input shall be based on the average hourly fuel usage rate during the test and the higher heating value of the fuel consumed if the boiler/heater is equipped with a fuel meter or the permitted maximum heat input if a fuel meter is not available.

11. REPORTING REQUIREMENTS AND RECORD KEEPING REQUIREMENTS

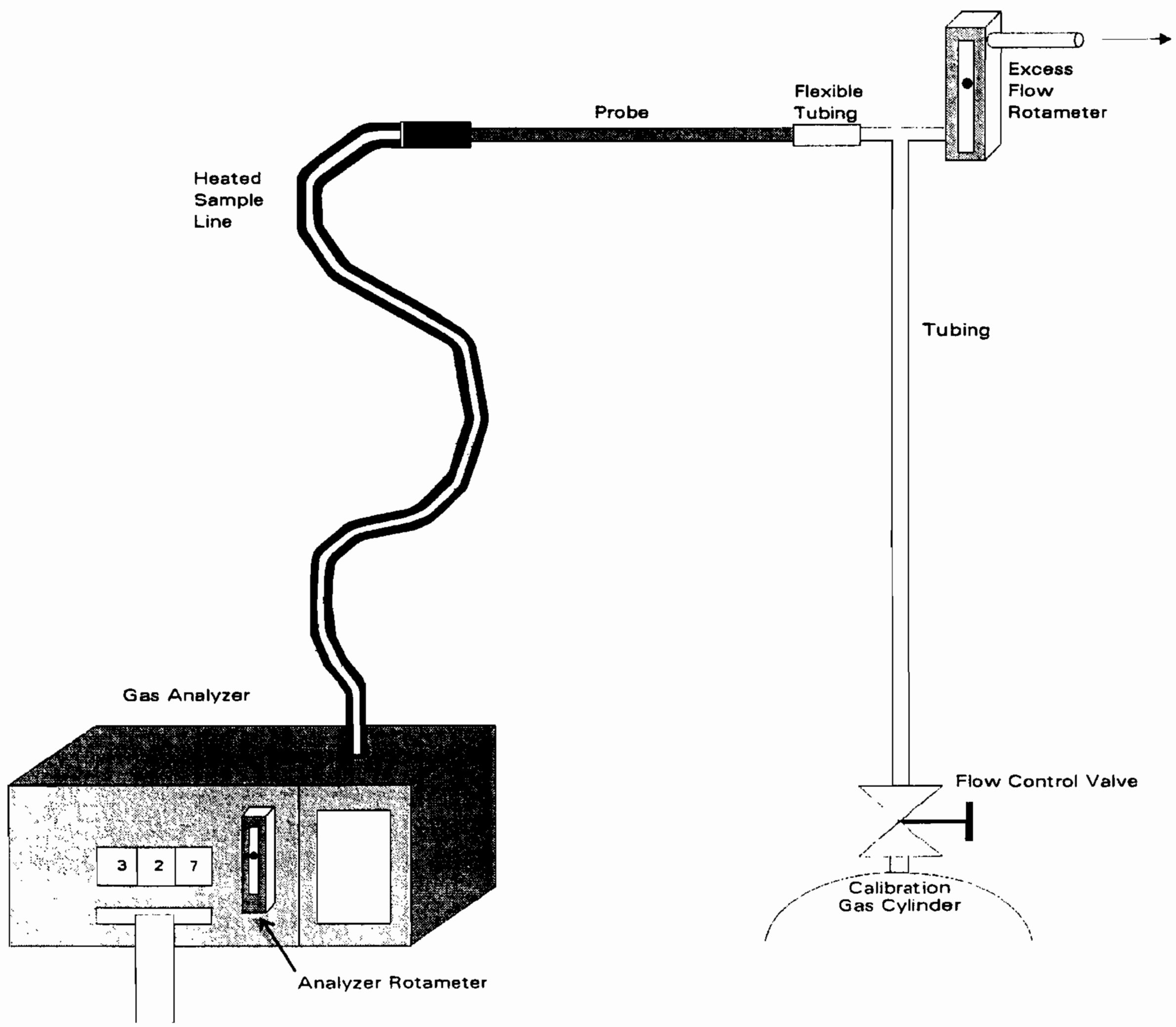
Test reports shall be submitted to the Air Quality Division within thirty (30) days of completing the test unless a specific reporting schedule is set by a condition of a permit. A separate test report shall be submitted for each emission source tested and, at a minimum, the following information shall be included:

- **Form A, Linearity Check Data Sheet,** Submit the linearity check as required by Section 6.2 for the nominal range tested.
- **Form B, Stability Check Data Sheet,** Submit the stability check as required by Section 6.4 for the nominal range tested.
- **Form C, Calibration Error Check Data Sheet**
- **Form D-1, D-2 or D-3,** Submit the appropriate test results form for type of source tested.
- If the manufacturer's specific fuel consumption is used, documentation from the manufacturer shall be submitted.
- If the horsepower is calculated during the test, information showing the derivation of the horsepower shall be included.

For sources subject to Section 30 of the Wyoming Air Quality Standards and Regulations, the submittal must be certified as truthful, accurate and complete by the facility's responsible official.

Records pertaining to the information above and supporting documentation shall be kept for five (5) years and made available upon request by this Division. Additionally, if the source is equipped with a fuel meter, records of all maintenance and calibrations of the fuel meter shall be kept for five (5) years from the date of the last maintenance or calibration.

FIGURE 1.
CALIBRATION SYSTEM SCHEMATIC



Form A

Linearity Check Data Sheet

Date:______________

Analyst:__________________________________

Analyzer Manufacturer/Model #:____

Analyzer Serial #:____

LINEARITY CHECK

Pollutant		Calibration Gas Concentration (Indicate Units)	Analyzer Response ppm NO	Analyzer Response ppm NO_2	Analyzer Response ppm CO	Analyzer Response % O_2	Absolute Difference (Indicate Units)	Percent of Span	Linearity Valid (Yes or No)
NO	Zero								
	Mid								
	Span								
NO_2	Zero								
	Mid								
	Span								
CO	Zero								
	Mid								
	Span								
O_2	Zero								
	Mid								
	Span								

Form B
Stability Check Data Sheet

Date:______________ **Analyst:**____

Analyzer Manufacturer/Model #:____

Analyzer Serial #:________________________________

Pollutant: NO, NO_2, CO (Circle One) **Span Gas Concentration (ppm):**______________

STABILITY CHECK					
Elapsed Time (Minutes)	Analyzer Response	Elapsed Time (Continued)	Analyzer Response	Elapsed Time (Continued)	Analyzer Response
1		17		33	
2		18		34	
3		19		35	
4		20		36	
5		21		37	
6		22		38	
7		23		39	
8		24		40	
9		25		41	
10		26		42	
11		27		43	
12		28		44	
13		29		45	
14		30		46	
15		31		47	
16		32		48	

For 30-minute Stability Check Period:

Maximum Concentration (ppm): __________ **Minimum Concentration (ppm):** __________

For 15-minute Stability Check Period:

Maximum Concentration (ppm): __________ **Minimum Concentration (ppm):** __________

Maximum Deviation = 100*(Max. Conc. - Min. Conc.)/Span Gas Conc. = __________ **percent**

Stability Time (minutes): __________

Form C
Calibration Error Check Data Sheet

Company:____________________ **Facility:**____________________

Source Tested:____________________ **Date:**____________________

Analyst:____________________ **Analyzer Serial #:**____________________

Analyzer Manufacturer/Model #:____________________

PRETEST CALIBRATION ERROR CHECK								
			A	B	|A-B|	|A-B|/SG*100		
		Pump Flow Rate (Indicate Units)	Analyzer Reading (Indicate Units)	Calibration Gas Concentration (Indicate Units)	Absolute Difference (Indicate Units)	Percent of Span Note 1	Calibration Valid (Yes or No)	Response Time (Minutes)
NO	Zero							
	Span							
NO_2	Zero							
	Span							
CO	Zero							
	Span							
O_2	Zero							
	Span							
		Pretest Calibration NO Cell Temperature (°F):						

SG = Span Gas

POST TEST CALIBRATION ERROR CHECK										
			A	B	|A-B|	|A-B|/SG*100			Interference Check	
		Pump Flow Rate (Indicate Units)	Analyzer Reading (Indicate Units)	Calibration Gas Concentration (Indicate Units)	Absolute Difference (Indicate Units)	Percent of Span Note 1	Calibration Valid (Yes or No)	Average of Pretest and Post Test Analyzer Readings (Indicate Units)	NO Monitor Response (ppm)	CO Monitor Response (ppm)
NO	Zero									
	Span									
NO_2	Zero									
	Span									
CO	Zero									
	Span									
O_2	Zero									
	Span									
		Post Test Calibration NO Cell Temperature (°F):								
		CO Interference Response (I_{CO}, %):				NO Interference Response (I_{NO}, %):				

SG= Span Gas

Note 1: The percent of span calculation is applicable to the NO, NO_2 and CO channels only.

Form D-1
Reciprocating Engine Test Results

Company:____________________ **Facility:**____________________

Source Tested:____________________ **Date:**____________________

Source Manufacturer/Model #:____________________

Site-rated Horsepower:____________________ **Source Serial #:**____________________

Type of Emission Control:____________________

Analyst:____________________ **Analyzer Serial #:**____________________

Analyzer Manufacturer/Model #:____________________

Operating Conditions

Source operating at 90 percent or greater site-rated horsepower during testing? yes no

Suction/ Discharge Pressures (Indicate Units)	Engine RPM	Engine Gas Throughput (Indicate Units)	Engine Fuel Consumption (Indicate Units)	Fuel Heat Content (Btu/cf)	Engine Specific Fuel Consumption (Btu/hp-hr)[1]	Engine Tested Horsepower

[1] As reported by the Manufacturer

Test Results

Test Start Time:__________ NO Cell Temperature (°F) after 1/3 (e.g., 7 minutes) of the test:__________

Test End Time:__________ NO Cell Temperature (°F) after 2/3 (e.g., 14 minutes) of the test:__________

NO_X ($NO + NO_2$)								
Avg. Tested NO ppm	$NO_{corrected}$ ppm	Avg. Tested NO_2 ppm	$NO_{2\ corrected}$ ppm	$NO_{X\ corrected}$ ppm	Tested gm/hp-hr	Tested lb/hr	Allowable gm/hp-hr	Allowable lb/hr

O_2		CO					
Avg. Tested O_2 %	$O_{2\ corrected}$ %	Avg. Tested CO ppm	$CO_{corrected}$ ppm	Tested gm/hp-hr	Tested lb/hr	Allowable gm/hp-hr	Allowable lb/hr

I certify to the best of my knowledge the test results are accurate and representative of the emissions from this source.

____________________ ____________________

Print Name **Signature**

Form D-2
Combustion Turbine Test Results

Company:______________________ **Facility:**______________________

Source Tested:______________________ **Date:**______________________

Source Manufacturer/Model #:______________________

Site-rated Horsepower:______________________ **Source Serial #:**______________________

Type of Emission Control:______________________

Analyst:______________________ **Analyzer Serial #:**______________________

Analyzer Manufacturer/Model #:______________________

Operating Conditions

Source operating at 90 percent or greater site-rated horsepower during testing? yes no

Suction/ Discharge Pressures (Indicate Units)	Turbine T_5 Temperature (°F)	Turbine RPM	Turbine Gas Throughput (Indicate Units)	Turbine Fuel Consumption (Indicate Units)	Fuel Heat Content (Btu/cf)	Turbine Specific Fuel Consumption (Btu/hp-hr)[1]	Turbine Tested Horsepower

[1] As reported by the Manufacturer

Test Results

Test Start Time:____________ NO Cell Temperature (°F) after 1/3 (e.g., 7 minutes) of the test:__________

Test End Time: ____________ NO Cell Temperature (°F) after 2/3 (e.g., 14 minutes) of the test:__________

NO_X ($NO + NO_2$)										
Avg. Tested NO ppm	$NO_{corrected}$ ppm	Avg. Tested NO_2 ppm	$NO_{2\ corrected}$ ppm	$NO_{X\ corrected}$ ppm	Tested gm/hp-hr	Tested lb/hr	Tested ppm @ 15% O2	Allowable gm/hp-hr	Allowable lb/hr	Allowable ppm @ 15% O2

O_2		CO							
Avg. Tested O_2 %	$O_{2\ corrected}$ %	Avg. Tested CO ppm	$CO_{corrected}$ ppm	Tested gm/hp-hr	Tested lb/hr	Tested ppm @ 15% O2	Allowable gm/hp-hr	Allowable lb/hr	Allowable ppm @ 15% O2

I certify to the best of my knowledge the test results are accurate and representative of the emissions from this source.

______________________ ______________________

Print Name **Signature**

Form D-3
Heater/Boiler Test Results

Company:________________________ **Facility:**________________________

Source Tested:________________________ **Date:**________________________

Source Manufacturer/Model #:____

Design Firing Rate (MMBtu/hr):____________ **Source Serial #:**________________________

Type of Emission Control:____

Analyst:________________________ **Analyzer Serial #:**________________________

Analyzer Manufacturer/Model #:____

Operating Conditions

Source operating at 90 percent or greater site-rated horsepower during testing? yes no

Fuel Consumption (cf/hr)	Fuel Heat Content (Btu/cf)	Heater/Boiler Tested Firing Rate (MMBtu/hr)

Test Results

Test Start Time:__________ NO Cell Temperature (°F) after 1/3 (e.g., 7 minutes) of the test:__________

Test End Time: __________ NO Cell Temperature (°F) after 2/3 (e.g., 14 minutes) of the test:__________

NO_X ($NO + NO_2$)								
Avg. Tested NO ppm	$NO_{corrected}$ ppm	Avg. Tested NO_2 ppm	$NO_{2\ corrected}$ ppm	$NO_{X\ corrected}$ ppm	Tested lb/MMBtu	Tested lb/hr	Allowable lb/MMBtu	Allowable lb/hr

O_2		CO					
Avg. Tested O_2 %	$O_{2\ corrected}$ %	Avg. Tested CO ppm	$CO_{corrected}$ ppm	Tested lb/MMBtu	Tested lb/hr	Allowable lb/MMBtu	Allowable lb/hr

I certify to the best of my knowledge the test results are accurate and representative of the emissions from this source.

________________________ ________________________

Print Name **Signature**

Appendix E

40 CFR Part 60, Subpart D

Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971

§ 60.40 Applicability and designation of affected facility.

(a) The affected facilities to which the provisions of this subpart apply are:

(1) Each fossil-fuel-fired steam generating unit of more than 73 megawatts heat input rate (250 million Btu per hour).

(2) Each fossil-fuel and wood-residue-fired steam generating unit capable of firing fossil fuel at a heat input rate of more than 73 megawatts (250 million Btu per hour).

(b) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels as defined in this subpart, shall not bring that unit under the applicability of this subpart.

(c) Except as provided in paragraph (d) of this section, any facility under paragraph (a) of this section that commenced construction or modification after August 17, 1971, is subject to the requirements of this subpart.

(d) The requirements of §60.44 (a)(4), (a)(5), (b) and (d), and 60.45(f)(4)(vi) are applicable to lignite-fired steam generating units that commenced construction or modification after December 22, 1976.

(e) Any facility covered under subpart Da is not covered under this subpart.

[42 FR 37936, July 25, 1977, as amended at 43 FR 9278, Mar. 7, 1978; 44 FR 33612, June 17, 1979]

§ 60.41 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, and in subpart A of this part.

(a) *Fossil-fuel fired steam generating unit* means a furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer.

(b) *Fossil fuel* means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials for the purpose of creating useful heat.

(c) *Coal refuse* means waste-products of coal mining, cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

(d) *Fossil fuel and wood residue-fired steam generating unit* means a furnace or boiler used in the process of burning fossil fuel and wood residue for the purpose of producing steam by heat transfer.

(e) *Wood residue* means bark, sawdust, slabs, chips, shavings, mill trim, and other wood products derived from wood processing and forest management operations.

(f) *Coal* means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM D388-77, 90, 91, 95, or 98a (incorporated by reference--see Sec. 60.17).

[39 FR 20791, June 14, 1974, as amended at 40 FR 2803, Jan. 16, 1975; 41 FR 51398, Nov. 22, 1976; 43 FR 9278, Mar. 7, 1978; 48 FR 3736, Jan. 27, 1983; 65 FR 61752, Oct. 17, 2000]

§ 60.42 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which:

(1) Contain particulate matter in excess of 43 nanograms per joule heat input (0.10 lb per million Btu) derived from fossil fuel or fossil fuel and wood residue.

(2) Exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity.

(b)(1) On or after December 28, 1979, no owner or operator shall cause to be discharged into the atmosphere from the Southwestern Public Service Company's Harrington Station #1, in Amarillo, TX, any gases which exhibit greater than 35 percent opacity, except that a maximum or 42 percent opacity shall be permitted for not more than 6 minutes in any hour.

(2) Interstate Power Company shall not cause to be discharged into the atmosphere from its Lansing Station Unit No. 4 in Lansing, IA, any gases which exhibit greater than 32 percent opacity, except that a maximum of 39 percent opacity shall be permitted for not more than six minutes in any hour.

[39 FR 20792, June 14, 1974, as amended at 41 FR 51398, Nov. 22, 1976; 42 FR 61537, Dec. 5, 1977; 44 FR 76787, Dec. 28, 1979; 45 FR 36077, May 29, 1980; 45 FR 47146, July 14, 1980; 46 FR 57498, Nov. 24, 1981; 61 FR 49976, Sept. 24, 1996; 65 FR 61752, Oct. 17, 2000]

§ 60.43 Standard for sulfur dioxide.

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of:

(1) 340 nanograms per joule heat input (0.80 lb per million Btu) derived from liquid fossil fuel or liquid fossil fuel and wood residue.

(2) 520 nanograms per joule heat input (1.2 lb per million Btu) derived from solid fossil fuel or solid fossil fuel and wood residue, except as provided in paragraph (e) of this section.

(b) When different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

$$PS_{SO_2} = \frac{y(340) + z(520)}{y + z}$$

where:

PS_{SO_2} is the prorated standard for sulfur dioxide when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired,

y is the percentage of total heat input derived from liquid fossil fuel, and

z is the percentage of total heat input derived from solid fossil fuel.

(c) Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.

(d) [Reserved]

(e) Units 1 and 2 (as defined in appendix G) at the Newton Power Station owned or operated by the Central Illinois Public Service Company will be in compliance with paragraph (a)(2) of this section if Unit 1 and Unit 2 individually comply with paragraph (a)(2) of this section or if the combined emission rate from Units 1 and 2 does not exceed 470 nanograms per joule (1.1 lb per million Btu) combined heat input to Units 1 and 2.

[39 FR 20792, June 14, 1974, as amended at 41 FR 51398, Nov. 22, 1976; 52 FR 28954, Aug. 4, 1987]

§ 60.44 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides, expressed as NO_2 in excess of :

(1) 86 nanograms per joule heat input (0.20 lb per million Btu) derived from gaseous fossil fuel.

(2) 129 nanograms per joule heat input (0.30 lb per million Btu) derived from liquid fossil fuel, liquid fossil fuel and wood residue, or gaseous fossil fuel and wood residue.

(3) 300 nanograms per joule heat input (0.70 lb per million Btu) derived from solid fossil fuel or solid fossil fuel and wood residue (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse).

(4) 260 nanograms per joule heat input (0.60 lb per million Btu) derived from lignite or lignite and wood residue (except as provided under paragraph (a)(5) of this section).

(5) 340 nanograms per joule heat input (0.80 lb per million Btu) derived from lignite which is mined in North Dakota, South Dakota, or Montana and which is burned in a cyclone-fired unit.

(b) Except as provided under paragraphs (c) and (d) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NO_x} = \frac{w(260) + x(86) + y(130) + z(300)}{w + x + y + z}$$

where:

PS_{NOx} = is the prorated standard for nitrogen oxides when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;

w = is the percentage of total heat input derived from lignite;

x = is the percentage of total heat input derived from gaseous fossil fuel;

y = is the percentage of total heat input derived from liquid fossil fuel; and

z = is the percentage of total heat input derived from solid fossil fuel (except lignite).

(c) When a fossil fuel containing at least 25 percent, by weight, of coal refuse is burned in combination with gaseous, liquid, or other solid fossil fuel or wood residue, the standard for nitrogen oxides does not apply.

(d) Cyclone-fired units which burn fuels containing at least 25 percent of lignite that is mined in North Dakota, South Dakota, or Montana remain subject to paragraph (a)(5) of this section regardless of the types of fuel combusted in combination with that lignite.

[39 FR 20792, June 14, 1974, as amended at 41 FR 51398, Nov. 22, 1976; 43 FR 9278, Mar. 7, 1978; 51 FR 42797, Nov. 25, 1986]

§ 60.45 Emission and fuel monitoring.

(a) Each owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxides emissions, and either oxygen or carbon dioxide except as provided in paragraph (b) of this section.

(b) Certain of the continuous monitoring system requirements under paragraph (a) of this section do not apply to owners or operators under the following conditions:

(1) For a fossil fuel-fired steam generator that burns only gaseous fossil fuel, continuous monitoring systems for measuring the opacity of emissions and sulfur dioxide emissions are not required.

(2) For a fossil fuel-fired steam generator that does not use a flue gas desulfurization device, a continuous monitoring system for measuring sulfur dioxide emissions is not required if the owner or operator monitors sulfur dioxide emissions by fuel sampling and analysis.

(3) Notwithstanding §60.13(b), installation of a continuous monitoring system for nitrogen oxides may be delayed until after the initial performance tests under §60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of nitrogen oxides are less than 70 percent of the applicable standards in §60.44, a continuous monitoring system for measuring nitrogen oxides emissions is not required. If the initial performance test results show that nitrogen oxide emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a continuous monitoring system for nitrogen oxides within one year after the date of the initial performance tests under §60.8 and comply with all other applicable monitoring requirements under this part.

(4) If an owner or operator does not install any continuous monitoring systems for sulfur oxides and nitrogen oxides, as provided under paragraphs (b)(1) and (b)(3) or paragraphs (b)(2) and (b)(3) of this section a continuous monitoring system for measuring either oxygen or carbon dioxide is not required.

(c) For performance evaluations under §60.13(c) and calibration checks under §60.13(d), the following procedures shall be used:

(1) Methods 6, 7, and 3B, as applicable, shall be used for the performance evaluations of sulfur dioxide and nitrogen oxides continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B are given in §60.46(d).

(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of appendix B to this part.

(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent and for a continuous monitoring system measuring sulfur oxides or nitrogen oxides the span value shall be determined as follows:

[in parts per million]

Fossil Fuel	Span value for sulfur dioxide	Span value for nitrogen oxides
Gas	(1)	500
Liquid	1,000	500
Solid	1,500	1,000
Combinations.	1,000y+1,500z	500(x+y)+1,000z

(1) Not applicable

where:

x = the fraction of total heat input derived from gaseous fossil fuel, and

y = the fraction of total heat input derived from liquid fossil fuel, and

z = the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under paragraph (c)(3) of this section for burning combinations of fossil fuels shall be rounded to the nearest 500 ppm.

(5) For a fossil fuel-fired steam generator that simultaneously burns fossil fuel and nonfossil fuel, the span value of all continuous monitoring systems shall be subject to the Administrator's approval.

(d) [Reserved]

(e) For any continuous monitoring system installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/million Btu):

(1) When a continuous monitoring system for measuring oxygen is selected, the measurement of the pollutant concentration and oxygen concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$$E = CF\left(\frac{20.9}{20.9 - \%O_2}\right)$$

where: E, C, F, and $\%O_2$ are determined under paragraph (f) of this section.

(2) When a continuous monitoring system for measuring carbon dioxide is selected, the measurement of the pollutant concentration and carbon dioxide concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$$E = CF_c\left(\frac{100}{\%CO_2}\right)$$

where: E, C, F_c and $\%CO_2$ are determined under paragraph (f) of this section.

(f) The values used in the equations under paragraphs (e) (1) and (2) of this section are derived as follows:

(1) *E*=pollutant emissions, ng/J (lb/million Btu).

(2) *C*=pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by $4.15x10^4$ M ng/dscm per ppm ($2.59x10^{-9}$ M lb/dscf per ppm) where *M*=pollutant molecular weight, g/g-mole (lb/lb-mole). *M*=64.07 for sulfur dioxide and 46.01 for nitrogen oxides.

(3) $\%O_2$, $\%CO_2$=oxygen or carbon dioxide volume (expressed as percent), determined with equipment specified under paragraph (a) of this section.

(4) F, F_c=a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of carbon dioxide generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

(i) For anthracite coal as classified according to ASTM D388-77, 90, 91, 95, or 98a (incorporated by reference-see §60.17), F=$2,723x10^{-17}$ dscm/J (10,140 dscf/million

Btu and $F_c=0.532\times10^{-17}$ scm CO_2/J (1,980 scf CO_2/million Btu).

(ii) For subbituminous and bituminous coal as classified according to ASTM D388-77, 90, 91, 95, or 98a (incorporated by reference-see §60.17), $F=2.637\times10^{-7}$ dscm/J (9,820 dscf/million Btu) and $F_c=0.486\times10^{-7}$ scm CO_2/J (1,810 scf CO_2/million Btu).

(iii) For liquid fossil fuels including crude, residual, and distillate oils, $F=2.476\times10^{-7}$ dscm/J (9,220 dscf/million Btu) and $F_c=0.384\times10^{-7}$ scm CO_2/J (1,430 scf CO_2/million Btu).

(iv) For gaseous fossil fuels, $F=2.347\times10^{-7}$ dscm/J (8,740 dscf/million Btu). For natural gas, propane, and butane fuels, $F_c=0.279\times10^{-7}$ scm CO_2/J (1,040 scf CO_2/million Btu) for natural gas, 0.322×10^{-7} scm CO_2/J (1,200 scf CO_2/million Btu) for propane, and 0.338×10^{-7} scm CO_2/J (1,260 scf CO_2/million Btu) for butane.

(v) For bark $F=2.589\times10^{-7}$ dscm/J (9,640 dscf/million Btu) and $F_c=0.500\times10^{-7}$ scm CO_2/J (1,840 scf CO_2/ million Btu). For wood residue other than bark $F=2.492\times10^{-7}$ dscm/J (9,280 dscf/million Btu) and $F_c=0.494\times10^{-7}$ scm CO_2/J (1,860 scf CO_2/ million Btu).

(vi) For lignite coal as classified according to ASTM D388-77, 90, 91, 95, or 98a (incorporated by reference-see §60.17), $F=2.659\times10^{-7}$ dscm/J (9,900 dscf/million Btu) and $F_c=0.516\times10^{-17}$ scm CO_2/J (1,920 scf CO_2/million Btu).

(5) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/million Btu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or F_c factor (scm CO_2/J, or scf CO_2/million Btu) on either basis in lieu of the F or F_c factors specified in paragraph (f)(4) of this section:

$$F = 10^{-6}\,\frac{227.2(\%H)+95.5(\%C)+35.6(\%S)+8.7(\%N)-28.7(\%O)}{GCV}$$

$$F_c = \frac{2.0\times10^{-5}(\%C)}{GCV(\text{SI units})}$$

$$F = \frac{10^{6}\left[3.64(\%H)+1.53(\%C)+0.57(\%S)+0.14(\%N)-0.46(\%O)\right]}{GCV(\text{English units})}$$

$$F_c = \frac{20.0(\%C)}{GCV(\text{SI units})}$$

$$F_c = \frac{321\times10^{3}(\%C)}{GCV(\text{English units})}$$

(i) H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM method D3178-73 (Reapproved 1979), 89 or D3176-74 or 89 (solid fuels) or computed from results using ASTM method D1137-53 or 75, D1945-64, 76, 91, or 96, or D1946-77 or 90 (Reapproved 1994) (gaseous fuels) as applicable. (These five methods are incorporated by reference-see §60.17.)

(ii) GVC is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015-77 (Reapproved 1978), 96, or D5865-98 for solid fuels and D1826-77 or 94 for gaseous fuels as applicable. (These two methods are incorporated by reference-see §60.17.)

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or F_c value shall be subject to the Administrator's approval.

(6) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or F_c factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i$$

or

$$F_c = \sum_{i=1}^{n} x_i (F_c)_i$$

where:

X_i = the fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.)

F_i or $(F_c)_i$ = the applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section.

n = the number of fuels being burned in combination.

(g) Excess emission and monitoring system performance reports shall be submitted to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter. Each excess emission and MSP report shall include the information required in §60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:

(1) *Opacity.* Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

(i) For sources subject to the opacity standard of §60.42(b)(1), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 35 percent opacity, except that one six-minute average per hour of up to 42 percent opacity need not be reported.

(ii) For sources subject to the opacity standard of §60.42(b)(2), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 32 percent opacity, except that one six-minute average per hour of up to 39 percent opacity need not be reported.

(iii) For sources subject to the opacity standard of §60.42(b)(3), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 30 percent opacity, except that one six-minute average per hour of up to 37 percent opacity need not be reported.

(2) *Sulfur dioxide.* Excess emissions for affected facilities are defined as:

(i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the applicable standard under §60.43.

(3) *Nitrogen oxides.* Excess emissions for affected facilities using a continuous monitoring system for measuring nitrogen oxides are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under §60.44.

[40 FR 46256, Oct. 6, 1975, 65 FR 61752, Oct. 17, 2000]

Editorial Note: For *Federal Register* citations affecting §60.45, see the List of CFR Sections Affected in the Finding Aids section of this volume.

§ 60.46 Test methods and procedures.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in paragraph (d) of this section.

(b) The owner or operator shall determine compliance with the particulate matter, SO_2, and NO_X standards in §60.42, 60.43, and 60.44 as follows:

(1) The emission rate (E) of particulate matter, SO_2, or NO_X shall be computed for each run using the following equation:

$$E = CF_d\left(\frac{20.9}{20.9-\%O_2}\right)$$

E = emission rate of pollutant, ng/J (1b/million Btu).

C = concentration of pollutant, ng/dscm (1b/dscf).

$\%O_2$ = oxygen concentration, percent dry basis.

F_d = factor as determined from Method 19.

(2) Method 5 shall be used to determine the particular matter concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems and Method 5B shall be used to determine the particulate matter concentration (C) after FGD systems.

(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train shall be set to provide an average gas temperature of 160±14℃ (320±25℉).

(ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration ($\%O_2$). The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of the sample O_2 concentrations at all traverse points.

(iii) If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O_2 traverse points.

(3) Method 9 and the procedures in §60.11 shall be used to determine opacity.

(4) Method 6 shall be used to determine the SO_2 concentration.

(i) The sampling site shall be the same as that selected for the particulate sample. The sampling location in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). The sampling time and sample volume for each sample run shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Two samples shall be taken during a 1-hour period, with each sample taken within a 30-minute interval.

(ii) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration ($\%O_2$). The O_2 sample shall be taken simultaneously with, and at the same point as, the SO_2 sample. The SO_2 emission rate shall be computed for each pair of SO_2 and O_2 samples. The SO_2 emission rate (E) for each run shall be the arithmetic mean of the results of the two pairs of samples.

(5) Method 7 shall be used to determine the NO_X concentration.

(i) The sampling site and location shall be the same as for the SO_2 sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.

(ii) For each NO_X sample, the emission rate correction factor, grab sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration ($\%O_2$). The sample shall be taken simultaneously with, and at the same point as, the NO_X sample.

(iii) The NO_X emission rate shall be computed for each pair of NO_X and O_2 samples. The NO_X emission rate (E) for each run shall be the arithmetic mean of the results of the four pairs of samples.

(c) When combinations of fossil fuels or fossil fuel and wood residue are fired, the owner or operator (in order to compute the prorated standard as shown in §60.43(b) and 60.44(b)) shall determine the percentage (w, x, y, or z) of the total heat input derived from each type of fuel as follows:

(1) The heat input rate of each fuel shall be determined by multiplying the gross calorific value of each fuel fired by the rate of each fuel burned.

(2) ASTM Methods D 2015-77 (Reapproved 1978), 96, or D5865-98 (solid fuels), D240-76 or 92 (liquid fuels), or D1826-77 or 94 (gaseous fuels) (incorporated by reference-see §60.17) shall be used to determine the gross calorific values of the fuels. The method used to determine the calorific value of wood residue must be approved by the Administrator.

(3) Suitable methods shall be used to determine the rate of each fuel burned during each test period, and a material balance over the steam generating system shall be used to confirm the rate.

(d) The owner or operator may use the following as alternatives to the reference methods and procedures in this section or in other sections as specified:

(1) The emission rate (E) of particulate matter, SO_2 and NO_X may be determined by using the F_c factor, provided that the following procedure is used:

(i) The emission rate (E) shall be computed using the following equation:

$$E = CF_c\left(\frac{100}{\%CO_2}\right)$$

where:

E = emission rate of pollutant, ng/J (lb/million Btu).

C = concentration of pollutant, ng/dscm (lb/dscf).

$\%CO_2$ = carbon dioxide concentration, percent dry basis.

F_c = factor as determined in appropriate sections of Method 19.

(ii) If and only if the average F_c factor in Method 19 is used to calculate E and either E is from 0.97 to 1.00 of the emission standard or the relative accuracy of a continuous emission monitoring system is from 17 to 20 percent, then three runs of Method 3B shall be used to determine the O_2 and CO_2 concentration according to the procedures in paragraph (b) (2)(ii), (4)(ii), or (5)(ii) of this section. Then if F_o (average of three runs), as calculated from the equation in Method 3B, is more than ±3 percent than the average F_o value, as determined from the average values of F_d and F_c in Method 19, i.e., F_{oa}=0.209 (F_{da}/F_{ca}), then the following procedure shall be followed:

(A) When F_o is less than 0.97 F_{oa}, then E shall be increased by that proportion under 0.97 F_{oa}, e.g., if F_o is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the emission standard.

(B) When F_o is less than 0.97 F_{os} and when the average difference (d) between the continuous monitor minus the reference methods is negative, then E shall be increased by that proportion under 0.97 F_{os}, e.g., if F_o is 0.95 F_{os}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(C) When F_o is greater than 1.03 F_{os} and when the average difference d is positive, then E shall be decreased by that proportion over 1.03 F_{os}, e.g., if F_o is 1.05 F_{os}, E shall be decreased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(2) For Method 5 or 5B, Method 17 may be used at facilities with or without wet FGD systems if the stack gas temperature at the sampling location does not exceed an average temperature of 160℃ (320℉). The procedures of sections 2.1 and 2.3 of Method 5B may be used with Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent gas is saturated or laden with water droplets.

(3) Particulate matter and SO_2 may be determined simultaneously with the Method 5 train provided that the following changes are made:

(i) The filter and impinger apparatus in sections 2.1.5 and 2.1.6 of Method 8 is used in place of the condenser (section 2.1.7) of Method 5.

(ii) All applicable procedures in Method 8 for the determination of SO_2 (including moisture) are used:

(4) For Method 6, Method 6C may be used. Method 6A may also be used whenever Methods 6 and 3B data are specified to determine the SO_2 emission rate, under the conditions in paragraph (d)(1) of this section.

(5) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be at least 1 hour and the integrated sampling approach shall be used to determine the O_2 concentration ($\%O_2$) for the emission rate correction factor.

(6) For Method 3, Method 3A or 3B may be used.

(7) For Method 3B, Method 3A may be used.

[54 FR 6662, Feb. 14, 1989; 54 FR 21344, May 17, 1989, as amended at 55 FR 5212, Feb. 14, 1990; 65 FR 61752, Oct. 17, 2000]

Appendix F
40 CFR Part 63, Subpart DDDDD

Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters

SOURCE: 69 FR 55253, September 13, 2004, unless otherwise noted.

What This Subpart Covers

§63.7480 What is the purpose of this subpart?

This subpart establishes national emission limits and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limits and work practice standards.

§63.7485 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in §63.7575 that is located at, or is part of, a major source of HAP as defined in §63.2 or §63.761 (40 CFR part 63, subpart HH, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities), except as specified in §63.7491.

§63.7490 What is the affected source of this subpart?

(a) This subpart applies to new, reconstructed, or existing affected sources as described in paragraphs (a)(1) and (2) of this section.

(1) The affected source of this subpart is the collection of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory located at a major source as defined in §63.7575.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or process heater located at a major source as defined in §63.7575.

(b) A boiler or process heater is new if you commence construction of the boiler or process heater after January 13, 2003, and you meet the applicability criteria at the time you commence construction.

(c) A boiler or process heater is reconstructed if you meet the reconstruction criteria as defined in §63.2, you commence reconstruction after January 13, 2003, and you meet the applicability criteria at the time you commence reconstruction.

(d) A boiler or process heater is existing if it is not new or reconstructed.

§63.7491 Are any boilers or process heaters not subject to this subpart?

The types of boilers and process heaters listed in paragraphs (a) through (o) of this section are not subject to this subpart.

(a) A municipal waste combustor covered by 40 CFR part 60, subpart AAAA, subpart BBBB, subpart Cb or subpart Eb.

(b) A hospital/medical/infectious waste incinerator covered by 40 CFR part 60, subpart Ce or subpart Ec.

(c) An electric utility steam generating unit that is a fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity, and supplies more than one-third of its potential electric output capacity, and more than 25 megawatts electrical output to any utility power distribution system for sale is considered an electric utility steam generating unit.

(d) A boiler or process heater required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by 40 CFR part 63, subpart EEE (*e.g.*, hazardous waste boilers).

(e) A commercial and industrial solid waste incineration unit covered by 40 CFR part 60, subpart CCCC or subpart DDDD.

(f) A recovery boiler or furnace covered by 40 CFR part 63, subpart MM.

(g) A boiler or process heater that is used specifically for research and development. This does not include units that only provide heat or steam to a process at a research and development facility.

(h) A hot water heater as defined in this subpart.

(i) A refining kettle covered by 40 CFR part 63, subpart X.

(j) An ethylene cracking furnace covered by 40 CFR part 63, subpart YY.

(k) Blast furnace stoves as described in the EPA document, entitled "National Emission Standards for Hazardous Air Pollutants (NESHAP) for Integrated Iron and Steel Plants— Background Information for Proposed Standards," (EPA-453/R-01-005).

(l) Any boiler and process heater specifically listed as an affected source in another standard(s) under 40 CFR part 63.

(m) Any boiler and process heater specifically listed as an affected source in another standard(s) established under section 129 of the Clean Air Act (CAA).

(n) Temporary boilers as defined in this subpart.

(o) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.

§63.7495 When do I have to comply with this subpart?

(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by November 12, 2004 or upon startup of your boiler or process heater, whichever is later.

(b) If you have an existing boiler or process heater, you must comply with this subpart no later than September 13, 2007.

(c) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, paragraphs (c)(1) and (2) of this section apply to you.

(1) Any new or reconstructed boiler or process heater at the existing facility must be in compliance with this subpart upon startup.

(2) Any existing boiler or process heater at the existing facility must be in compliance with this subpart within 3 years after the facility becomes a major source.

(d) You must meet the notification requirements in §63.7545 according to the schedule in §63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

Emission Limits and Work Practice Standards

§63.7499 What are the subcategories of boilers and process heaters?

The subcategories of boilers and process heaters are large solid fuel, limited use solid fuel, small solid fuel, large liquid fuel, limited use liquid fuel, small liquid fuel, large gaseous fuel, limited use gaseous fuel, and small gaseous fuel. Each subcategory is defined in §63.7575.

§63.7500 What emission limits, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) and (2) of this section.

(1) You must meet each emission limit and work practice standard in Table 1 to this subpart that applies to your boiler or process heater, except as provided under §63.7507.

(2) You must meet each operating limit in Tables 2 through 4 to this subpart that applies to your boiler or process heater. If you use a control device or combination of control devices not covered in Tables 2 through 4 to this subpart, or you wish to establish and monitor an alternative operating limit and alternative monitoring parameters, you must apply to the United States Environmental Protection Agency (EPA) Administrator for approval of alternative monitoring under §63.8(f).

(b) As provided in §63.6(g), EPA may approve use of an alternative to the work practice standards in this section.

General Compliance Requirements

§63.7505 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits (including operating limits) and the work practice standards in this subpart at all times, except during periods of startup, shutdown, and malfunction.

(b) You must always operate and maintain your affected source, including air pollution control and monitoring equipment, according to the provisions in §63.6(e)(1)(i).

(c) You can demonstrate compliance with any applicable emission limit using fuel analysis if the emission rate calculated according to §63.7530(d) is less than the applicable emission limit. Otherwise, you must demonstrate compliance using performance testing.

(d) If you demonstrate compliance with any applicable emission limit through performance testing, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of this section. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under §63.8(f).

(1) For each continuous monitoring system (CMS) required in this section, you must develop and submit to the EPA Administrator for approval a site-specific monitoring plan that addresses paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan at least 60 days before your initial performance evaluation of your CMS.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (*e.g.*, on or downstream of the last control device);

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems; and

(iii) Performance evaluation procedures and acceptance criteria (*e.g.*, calibrations).

(2) In your site-specific monitoring plan, you must also address paragraphs (d)(2)(i) through (iii) of this section.

(i) Ongoing operation and maintenance procedures in accordance with the general requirements of §63.8(c)(1), (c)(3), and (c)(4)(ii);

(ii) Ongoing data quality assurance procedures in accordance with the general requirements of §63.8(d); and

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of §63.10(c), (e)(1), and (e)(2)(i).

(3) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

(4) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

(e) If you have an applicable emission limit or work practice standard, you must develop and implement a written startup, shutdown, and malfunction plan (SSMP) according to the provisions in §63.6(e)(3).

§63.7506 Do any boilers or process heaters have limited requirements?

(a) New or reconstructed boilers and process heaters in the large liquid fuel subcategory or the limited use liquid fuel subcategory that burn only fossil fuels and other gases and do not burn any residual oil are subject to the emission limits and applicable work practice standards in Table 1 to this subpart. You are not required to conduct a performance test to demonstrate compliance with the emission limits. You are not required to set and maintain operating limits to demonstrate continuous compliance with the emission limits. However, you must meet the requirements in paragraphs (a)(1) and (2) of this section and meet the CO work practice standard in Table 1 to this subpart.

(1) To demonstrate initial compliance, you must include a signed statement in the Notification of Compliance Status report required in §63.7545(e) that indicates you burn only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels.

(2) To demonstrate continuous compliance with the applicable emission limits, you must also keep records that demonstrate that you burn only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels. You must also include a signed statement in each semiannual compliance report required in §63.7550 that indicates you burned only liquid fossil fuels other than residual oils, either alone or in combination with gaseous fuels, during the reporting period.

(b) The affected boilers and process heaters listed in paragraphs (b)(1) through (3) of this section are subject to only the initial notification requirements in §63.9(b) (*i.e.*, they are not subject to the emission limits, work practice standards, performance testing, monitoring, SSMP, site-specific monitoring plans, recordkeeping and reporting requirements of this subpart or any other requirements in subpart A of this part).

(1) Existing large and limited use gaseous fuel units.

(2) Existing large and limited use liquid fuel units.

(3) New or reconstructed small liquid fuel units that burn only gaseous fuels or distillate oil. New or reconstructed small liquid fuel boilers and process heaters that commence burning of any other type of liquid fuel must comply with all applicable requirements of this subpart and subpart A of this part upon startup of burning the other type of liquid fuel.

(c) The affected boilers and process heaters listed in paragraphs (c)(1) through (4) of this section are not subject to the initial notification requirements in §63.9(b) and are not subject to any requirements in this subpart or in subpart A of this part (*i.e.*, they are not subject to the emission limits, work practice standards, performance testing, monitoring, SSM plans, site-specific monitoring plans, recordkeeping and reporting requirements of this subpart, or any other requirements in subpart A of this part.

(1) Existing small solid fuel boilers and process heaters.

(2) Existing small liquid fuel boilers and process heaters.

(3) Existing small gaseous fuel boilers and process heaters.

(4) New or reconstructed small gaseous fuel units.

§63.7507 What are the health-based compliance alternatives for the hydrogen chloride (HCl) and total selected metals (TSM) standards?

(a) As an alternative to the requirement for large solid fuel boilers located at a single facility to demonstrate compliance with the HCl emission limit in Table 1 to this subpart, you may demonstrate eligibility for the health-based compliance alternative for HCl emissions under the procedures prescribed in appendix A to this subpart.

(b) In lieu of complying with the TSM emission standards in Table 1 to this subpart based on the sum of emissions for the eight selected metals, you may demonstrate eligibility for complying with the TSM emission standards in Table 1 based on the sum of emissions for seven selected metals (by excluding manganese emissions from the summation of TSM emissions) under the procedures prescribed in appendix A to this subpart.

Testing, Fuel Analyses, and Initial Compliance Requirements

§63.7510 What are my initial compliance requirements and by what date must I conduct them?

(a) For affected sources that elect to demonstrate compliance with any of the emission limits of this subpart through performance testing, your initial compliance requirements include conducting performance tests according to §63.7520 and Table 5 to this subpart, conducting a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to this subpart, establishing operating limits according to §63.7530 and Table 7 to this subpart, and conducting CMS performance evaluations according to §63.7525.

(b) For affected sources that elect to demonstrate compliance with the emission limits for HCl, mercury, or TSM through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to §63.7521 and Table 6 to this subpart and establish operating limits according to §63.7530 and Table 8 to this subpart.

(c) For affected sources that have an applicable work practice standard, your initial compliance requirements depend on the subcategory and rated capacity of your boiler or process heater. If your boiler or process heater is in any of the limited use subcategories or has a heat input capacity less than 100 MMBtu per hour, your initial compliance demonstration is conducting a performance test for carbon monoxide according to Table 5 to this subpart. If your boiler or process heater is in any of the large subcategories and has a heat input capacity of 100 MMBtu per hour or greater, your initial compliance demonstration is conducting a performance evaluation of your continuous emission monitoring system for carbon monoxide according to §63.7525(a).

(d) For existing affected sources, you must demonstrate initial compliance no later than 180 days after the compliance date that is specified for your source in §63.7495 and according to the applicable provisions in §63.7(a)(2) as cited in Table 10 to this subpart.

(e) If your new or reconstructed affected source commenced construction or reconstruction between January 13, 2003 and November 12, 2004, you must demonstrate initial compliance with either the proposed emission limits and work practice standards or the promulgated emission limits and work practice standards no later than 180 days after November 12, 2004 or within 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(f) If your new or reconstructed affected source commenced construction or reconstruction between January 13, 2003, and November 12, 2004, and you chose to comply with the proposed emission limits and work practice standards when demonstrating initial compliance, you must conduct a second compliance demonstration for the promulgated emission limits and work practice standards within 3 years after November 12, 2004 or within 3 years after startup of the affected source, whichever is later.

(g) If your new or reconstructed affected source commences construction or reconstruction after November 12, 2004, you must demonstrate initial compliance with the promulgated emission limits and work practice standards no later than 180 days after startup of the source.

§63.7515 When must I conduct subsequent performance tests or fuel analyses?

(a) You must conduct all applicable performance tests according to §63.7520 on an annual basis, unless you follow the requirements listed in paragraphs (b) through (d) of this section. Annual performance tests must be completed between 10 and 12 months after the previous performance test, unless you follow the requirements listed in paragraphs (b) through (d) of this section.

(b) You can conduct performance tests less often for a given pollutant if your performance tests for the pollutant (particulate matter, HCl, mercury, or TSM) for at least 3 consecutive years show that you comply with the emission limit. In this case, you do not have to conduct a performance test for that pollutant for the next 2 years. You must conduct a performance test during the third year and no more than 36 months after the previous performance test.

(c) If your boiler or process heater continues to meet the emission limit for particulate matter, HCl, mercury, or TSM, you may choose to conduct performance tests for these pollutants every third year, but each such performance test must be conducted no more than 36 months after the previous performance test.

(d) If a performance test shows noncompliance with an emission limit for particulate matter, HCl, mercury, or TSM, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 3-year period show compliance.

(e) If you have an applicable work practice standard for carbon monoxide and your boiler or process heater is in any of the limited use subcategories or has a heat input capacity less than 100 MMBtu per hour, you must conduct annual performance tests for carbon monoxide according to §63.7520. Each annual performance test must be conducted between 10 and 12 months after the previous performance test.

(f) You must conduct a fuel analysis according to §63.7521 for each type of fuel burned no later than 5 years after the previous fuel analysis for each fuel type. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in §63.7540.

(g) You must report the results of performance tests and fuel analyses within 60 days after the completion of the performance tests or fuel analyses. This report should also verify that the operating limits for your affected source have not changed or provide documentation of revised operating parameters established according to §63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests and fuel analyses should include all applicable information required in §63.7550.

§63.7520 What performance tests and procedures must I use?

(a) You must conduct all performance tests according to §63.7(c), (d), (f), and (h). You must also develop a site-specific test plan according to the requirements in §63.7(c) if you elect to demonstrate compliance through performance testing.

(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.

(c) New or reconstructed boilers or process heaters in one of the liquid fuel subcategories that burn only fossil fuels and other gases and do not burn any residual oil must demonstrate compliance according to §63.7506(a).

(d) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at the maximum normal operating load while burning the type of fuel or mixture of fuels that have the highest content of chlorine, mercury, and total selected metals, and you must demonstrate initial compliance and establish your operating limits based on these tests. These requirements could result in the need to conduct more than one performance test.

(e) You may not conduct performance tests during periods of startup, shutdown, or malfunction.

(f) You must conduct three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour.

(g) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 of appendix A to part 60 of this chapter to convert the measured particulate matter concentrations, the measured HCl concentrations, the measured TSM concentrations, and the measured mercury concentrations that result from the initial performance test to pounds per million Btu heat input emission rates using F-factors.

§63.7521 What fuel analyses and procedures must I use?

(a) You must conduct fuel analyses according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable.

(b) You must develop and submit a site-specific fuel analysis plan to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section.

(1) You must submit the fuel analysis plan no later than 60 days before the date that you intend to demonstrate compliance.

(2) You must include the information contained in paragraphs (b)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all fuel types anticipated to be burned in each boiler or process heater.

(ii) For each fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.

(iv) For each fuel type, the analytical methods, with the expected minimum detection levels, to be used for the measurement of selected total metals, chlorine, or mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that will be used.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(c) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section.

(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.

(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. Collect all the material (fines and coarse) in the full cross-section. Transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal intervals during the testing period.

(2) If sampling from a fuel pile or truck, collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, dig into the pile to a depth of 18 inches. Insert a clean flat square shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling.

(iii) Transfer all samples to a clean plastic bag for further processing.

(d) Prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section

(1) Thoroughly mix and pour the entire composite sample over a clean plastic sheet.

(2) Break sample pieces larger than 3 inches into smaller sizes.

(3) Make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) Separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) Grind the sample in a mill.

(7) Use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

(e) Determine the concentration of pollutants in the fuel (mercury, chlorine, and/or total selected metals) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 6 to this subpart.

§63.7522 Can I use emission averaging to comply with this subpart?

(a) As an alternative to meeting the requirements of §63.7500, if you have more than one existing large solid fuel boiler located at your facility, you may demonstrate compliance by emission averaging according to the procedures in this section in a State that does not choose to exclude emission averaging.

(b) For each existing large solid fuel boiler in the averaging group, the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on November 12, 2004 or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology employed on November 12, 2004.

(c) You may average particulate matter or TSM, HCl, and mercury emissions from existing large solid fuel boilers to demonstrate compliance with the limits in Table 1 to this subpart if you satisfy the requirements in paragraphs (d), (e), and (f) of this section.

(d) The weighted average emissions from the existing large solid fuel boilers participating in the emissions averaging option must be in compliance with the limits in Table 1 to this subpart at all times following the compliance date specified in §63.7495.

(e) You must demonstrate initial compliance according to paragraphs (e)(1) or (2) of this section.

(1) You must use Equation 1 of this section to demonstrate that the particulate matter or TSM, HCl, and mercury emissions from all existing large solid fuel boilers participating in the emissions averaging option do not exceed the emission limits in Table 1 to this subpart.

$$\text{AveWeighted Emissions} = \sum_{i=1}^{n} (Er \times Hm) \div \sum_{i=1}^{n} Hm \qquad \text{(Eq.1)}$$

Where:

AveWeighted = Average weighted emissions for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as calculated according to Table 5 to this subpart) or fuel analysis (as calculated by the applicable equation in §63.7530(d)) for boiler, i, for particulate matter of TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

Hm = Maximum rated heat input capacity of boiler, i, in units of million Btu per hour.

n = Number of large solid fuel boilers participating in the emissions averaging option.

(2) If you are not capable of monitoring heat input, you can use Equation 2 of this section as an alternative to using Equation 1 of this section to demonstrate that the particulate matter or TSM, HCl, and mercury emissions from all existing large solid fuel boilers participating in the emissions averaging option do not exceed the emission limits in Table 1 to this subpart.

$$\text{AveWeighted Emissions} = \sum_{i=1}^{n} (Er \times Sm \times Cf) \div \sum_{i=1}^{n} Sm \times Cf \qquad \text{(Eq. 2)}$$

Where:

AveWeighted = Average weighted emission level for PM or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as calculated according to Table 5 to this subpart) or fuel analysis (as calculated by the applicable equation in §63.7530(d)) for boiler, i, for particulate matter of TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

Sm = Maximum steam generation by boiler, i, in units of pounds.

Cf = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of stream generated.

(f) You must demonstrate continuous compliance on a 12-month rolling average basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) and (2). The first 12-month rolling average period begins on the compliance date specified in §63.7495.

(1) For each calendar month, you must use Equation 3 of this section to calculate the 12-month rolling average weighted emission limit using the actual heat capacity for each existing large solid fuel boiler participating in the missions averaging option.

$$\text{AveWeighted Emissions} = \sum_{i=1}^{n} (Er \times Hb) \div \sum_{i=1}^{n} Hb \qquad \text{(Eq. 3)}$$

Where:

AveWeighted Emissions = 12-month rolling average weighted emission level for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate, calculated during the most recent compliance test, (as calculated according to Table 5 to this subpart) or fuel analysis (as calculated by the applicable equation in §63.7530(d)) for boiler, i, for particulate matter of TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

Hb = The average heat input for each calendar month of boiler, i, in units of million Btu.

n = Number of large solid fuel boilers participating in the emissions averaging option.

(2) If you are not capable of monitoring the heat input, you can use Equation 4 of this section as an alternative to using Equation 3 of the section to calculate the 12-month rolling average weighted emission limit using the actual steam generation from the large solid fuel boilers participating in the emissions averaging option.

$$\text{AveWeighted Emissions} = \sum_{i=1}^{n} (Er \times Sa \times Cf) \div \sum_{i=1}^{n} Sa \times Cf \qquad \text{(Eq. 4)}$$

Where:

AveWeighted Emissions = 12-month rolling average weighted emission level for PM or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate, calculated during the most recent compliance test, (as calculated according to Table 5 to this subpart) or fuel analysis (as calculated by the applicable equation in §63.7530(d)) for boiler, i, for particulate matter or TSM, HCl, or mercury, in units of pounds per million Btu of heat input.

Sa = Actual steam generation for each calendar month by boiler, i, in units of pounds.

Cf = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of stream generated.

(g) You must develop and submit an implementation plan for emission averaging to the applicable regulatory authority for review and approval according to the following procedures and requirements in paragraphs (g)(1) through (4).

(1) You must submit the implementation plan no later than 180 days before the date that the facility intends to demonstrate compliance using the emission averaging option.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vii) of this section in your implementation plan for all emission sources included in an emissions average:

(i) The identification of all existing large solid fuel boilers in the averaging group, including for each either the applicable HAP emission level or the control technology installed on;

(ii) The process parameter (heat input or steam generated) that will be monitored for each averaging group of large solid fuel boilers;

(iii) The specific control technology or pollution prevention measure to be used for each emission source in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple sources, the owner or operator must identify each source;

(iv) The test plan for the measurement of particulate matter (or TSM), HCl, or mercury emissions in accordance with the requirements in §63.7520;

(v) The operating parameters to be monitored for each control system or device and a description of how the operating limits will be determined;

(vi) If you request to monitor an alternative operating parameter pursuant to §63.7525, you must also include:

(A) A description of the parameter(s) to be monitored and an explanation of the criteria used to select the parameter(s); and

(B) A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device; the frequency and content of monitoring, reporting, and recordkeeping requirements; and a demonstration, to the satisfaction of the applicable regulatory authority, that the proposed monitoring frequency is sufficient to represent control device operating conditions; and

(vii) A demonstration that compliance with each of the applicable emission limit(s) will be achieved under representative operating conditions.

(3) Upon receipt, the regulatory authority shall review and approve or disapprove the plan according to the following criteria:

(i) Whether the content of the plan includes all of the information specified in paragraph (g)(2) of this section; and

(ii) Whether the plan presents sufficient information to determine that compliance will be achieved and maintained.

(4) The applicable regulatory authority shall not approve an emission averaging implementation plan containing any of the following provisions:

(i) Any averaging between emissions of differing pollutants or between differing sources; or

(ii) The inclusion of any emission source other than an existing large solid fuel boiler.

§63.7525 What are my monitoring, installation, operation, and maintenance requirements?

(a) If you have an applicable work practice standard for carbon monoxide, and your boiler or process heater is in any of the large subcategories and has a heat input capacity of 100 MMBtu per hour or greater, you must install, operate, and maintain a continuous emission monitoring system (CEMS) for carbon monoxide according to the procedures in paragraphs (a)(1) through (6) of this section by the compliance date specified in §63.7495.

(1) Each CEMS must be installed, operated, and maintained according to Performance Specification (PS) 4A of 40 CFR part 60, appendix B, and according to the site-specific monitoring plan developed according to §63.7505(d).

(2) You must conduct a performance evaluation of each CEMS according to the requirements in §63.8 and according to PS 4A of 40 CFR part 60, appendix B.

(3) Each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) The CEMS data must be reduced as specified in §63.8(g)(2).

(5) You must calculate and record a 30-day rolling average emission rate on a daily basis. A new 30-day rolling average emission rate is calculated as the average of all of the hourly CO emission data for the preceding 30 operating days.

(6) For purposes of calculating data averages, you must not use data recorded during periods of monitoring malfunctions, associated repairs, out-of-control periods, required quality assurance or control activities, or when your boiler or process heater is operating at less than 50 percent of its rated capacity. You must use all the data collected during all other periods in assessing compliance. Any period for which the monitoring system is out of control and data are not available for required calculations constitutes a deviation from the monitoring requirements.

(b) If you have an applicable opacity operating limit, you must install, operate, certify and maintain each continuous opacity monitoring system (COMS) according to the procedures in paragraphs (b)(1) through (7) of this section by the compliance date specified in §63.7495.

(1) Each COMS must be installed, operated, and maintained according to PS 1 of 40 CFR part 60, appendix B.

(2) You must conduct a performance evaluation of each COMS according to the

requirements in §63.8 and according to PS 1 of 40 CFR part 60, appendix B

(3) As specified in §63.8(c)(4)(i), each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(4) The COMS data must be reduced as specified in §63.8(g)(2).

(5) You must include in your site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in §63.8(d). At a minimum, the monitoring plan must include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS.

(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of §63.8(e). Identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit.

(7) You must determine and record all the 6-minute averages (and 1-hour block averages as applicable) collected for periods during which the COMS is not out of control.

(c) If you have an operating limit that requires the use of a CMS, you must install, operate, and maintain each continuous parameter monitoring system (CPMS) according to the procedures in paragraphs (c)(1) through (5) of this section by the compliance date specified in §63.7495.

(1) The CPMS must complete a minimum of one cycle of operation for each successive 15-minute period. You must have a minimum of four successive cycles of operation to have a valid hour of data.

(2) Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must conduct all monitoring in continuous operation at all times that the unit is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(3) For purposes of calculating data averages, you must not use data recorded during monitoring malfunctions, associated repairs, out of control periods, or required quality assurance or control activities. You must use all the data collected during all other periods in assessing compliance. Any period for which the monitoring system is out-of-control and data are not available for required calculations constitutes a deviation from the monitoring requirements.

(4) Determine the 3-hour block average of all recorded readings, except as provided in paragraph (c)(3) of this section.

(5) Record the results of each inspection, calibration, and validation check.

(d) If you have an operating limit that requires the use of a flow measurement device, you must meet the requirements in paragraphs (c) and (d)(1) through (4) of this section.

(1) Locate the flow sensor and other necessary equipment in a position that provides a representative flow.

(2) Use a flow sensor with a measurement sensitivity of 2 percent of the flow rate.

(3) Reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(4) Conduct a flow sensor calibration check at least semiannually.

(e) If you have an operating limit that requires the use of a pressure measurement device, you must meet the requirements in paragraphs (c) and (e)(1) through (6) of this section.

(1) Locate the pressure sensor(s) in a position that provides a representative measurement of the pressure.

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion.

(3) Use a gauge with a minimum tolerance of 1.27 centimeters of water or a transducer with a minimum tolerance of 1 percent of the pressure range.

(4) Check pressure tap pluggage daily.

(5) Using a manometer, check gauge calibration quarterly and transducer calibration monthly.

(6) Conduct calibration checks any time the sensor exceeds the manufacturer's specified maximum operating pressure range or install a new pressure sensor.

(f) If you have an operating limit that requires the use of a pH measurement device, you must meet the requirements in paragraphs (c) and (f)(1) through (3) of this section.

(1) Locate the pH sensor in a position that provides a representative measurement of scrubber effluent pH.

(2) Ensure the sample is properly mixed and representative of the fluid to be measured.

(3) Check the pH meter's calibration on at least two points every 8 hours of process operation.

(g) If you have an operating limit that requires the use of equipment to monitor voltage and secondary current (or total power input) of an electrostatic precipitator (ESP), you must use voltage and secondary current monitoring equipment to measure voltage and secondary current to the ESP.

(h) If you have an operating limit that requires the use of equipment to monitor sorbent injection rate (*e.g.*, weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (c) and (h)(1) through (3) of this section.

(1) Locate the device in a position(s) that provides a representative measurement of the total sorbent injection rate.

(2) Install and calibrate the device in accordance with manufacturer's procedures and specifications.

(3) At least annually, calibrate the device in accordance with the manufacturer's procedures and specifications.

(i) If you elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate a bag leak detection system as specified in paragraphs (i)(1) through (8) of this section.

(1) You must install and operate a bag leak detection system for each exhaust stack of the fabric filter.

(2) Each bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with the guidance provided in EPA–454/R–98–015, September 1997.

(3) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.

(4) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.

(5) The bag leak detection system must be equipped with a device to continuously record the output signal from the sensor.

(6) The bag leak detection system must be equipped with an alarm system that will sound automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard by plant operating personnel.

(7) For positive pressure fabric filter systems that do not duct all compartments of cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.

(8) Where multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors.

§63.7530 How do I demonstrate initial compliance with the emission limits and work practice standards?

(a) You must demonstrate initial compliance with each emission limit and work practice standard that applies to you by either conducting initial performance tests and establishing operating limits, as applicable, according to §63.7520, paragraph (c) of this section, and Tables 5 and 7 to this subpart OR conducting initial fuel analyses to determine emission rates and establishing operating limits, as applicable, according to §63.7521, paragraph (d) of this section, and Tables 6 and 8 to this subpart.

(b) New or reconstructed boilers or process heaters in one of the liquid fuel subcategories that burn only fossil fuels and other gases and do not burn any residual oil must demonstrate compliance according to §63.7506(a).

(c) If you demonstrate compliance through performance testing, you must establish each site-specific operating limit in Tables 2 through 4 to this subpart that applies to you according to the requirements in §63.7520, Table 7 to this subpart, and paragraph (c)(4) of this section, as applicable. You must also conduct fuel analyses according to §63.7521 and establish maximum fuel pollutant input levels according to paragraphs (c)(1) through (3) of this section, as applicable.

(1) You must establish the maximum chlorine fuel input (Cinput) during the initial performance testing according to the procedures in paragraphs (c)(1)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of chlorine.

(ii) During the performance testing for HCl, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (Ci).

(iii) You must establish a maximum chlorine input level using Equation 5 of this section.

$$Cl_{input} = \sum_{i=1}^{n} \left[(C_i)(Q_i)\right] \quad \text{(Eq. 5)}$$

Where:

Cl_{input} = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.

C_i = Arithmetic average concentration of chlorine in fuel type, i, analyzed according to §63.7521, in units of pounds per million Btu.

Q_i = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of "1" for Q_i.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

(2) If you choose to comply with the alternative TSM emission limit instead of the particulate matter emission limit, you must establish the maximum TSM fuel input level (TSM_{input}) during the initial performance testing according to the procedures in paragraphs (c)(2)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of TSM.

(ii) During the performance testing for TSM, you must determine the fraction of total heat input from each fuel burned (Q_i) based on the fuel mixture that has the highest content of total selected metals, and the average TSM concentration of each fuel type burned (M_i).

(iii) You must establish a baseline TSM input level using Equation 6 of this section.

$$TSM_{input} = \sum_{i=1}^{n} \left[(M_i)(Q_i)\right] \quad \text{(Eq. 6)}$$

Where:

TSM_{input} = Maximum amount of TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu.

M_i = Arithmetic average concentration of TSM in fuel type, i, analyzed according to §63.7521, in units of pounds per million Btu.

Q_i = Fraction of total heat input from based fuel type, i, based on the fuel mixture that has the highest content of TSM. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of "1" for Q_i.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.

(3) You must establish the maximum mercury fuel input level ($Mercury_{input}$) during the initial performance testing using the procedures in paragraphs (c)(3)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of mercury.

(ii) During the compliance demonstration for mercury, you must determine the fraction of total heat input for each fuel burned (Qi) based on the fuel mixture that has the highest content of mercury, and the average mercury concentration of each fuel type burned (HGi).

(iii) You must establish a maximum mercury input level using Equation 7 of this section.

$$Mercury_{input} = \sum_{i=1}^{n} \left[(HG_i)(Q_i)\right] \quad \text{(Eq. 7)}$$

Where:

$Mercury_{input}$ = Maximum amount of mercury entering the boiler or process heater through fuels burned in units of pounds per million Btu.

HG_i = Arithmetic average concentration of mercury in fuel type, i, analyzed according to §63.7521, in units of pounds per million Btu.

Q_i = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of "1" for Q_i.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of mercury.

(4) You must establish parameter operating limits according to paragraphs (c)(4)(i) through (iv) of this section.

(i) For a wet scrubber, you must establish the minimum scrubber effluent pH, liquid flowrate, and pressure drop as defined in §63.7575, as your operating limits during the three-run performance test. If you use a wet scrubber and you conduct separate performance tests for particulate matter, HCl, and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flowrate, and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flowrate and pressure drop operating limits at the highest minimum values established during the performance tests.

(ii) For an electrostatic precipitator, you must establish the minimum voltage and secondary current (or total power input), as defined in §63.7575, as your operating limits during the three-run performance test.

(iii) For a dry scrubber, you must establish the minimum sorbent injection rate, as defined in §63.7575, as your operating limit during the three-run performance test.

(iv) The operating limit for boilers or process heaters with fabric filters that choose to demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in §63.7525, and that each fabric filter must be operated such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during a 6-month period.

(d) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to §63.7521 and follow the procedures in paragraphs (d)(1) through (5) of this section.

(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your boiler or process heater that would result in the maximum emission rates of the pollutants that you elect to demonstrate compliance through fuel analysis.

(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided z-statistic test described in Equation 8 of this section.

$$P_{90} = \text{mean} + (SD \times t) \quad \text{(Eq. 8)}$$

Where:

P_{90} = 90th percentile confidence level pollutant concentration, in pounds per million Btu.

mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to §63.7521, in units of pounds per million Btu.

SD = Standard deviation of the pollutant concentration in the fuel samples analyzed according to §63.7521, in units of pounds per million Btu.

t = t distribution critical value for 90th percentile (0.1) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a Distribution Critical Value Table.

(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your boiler or process heater using Equation 9 of this section must be less than the applicable emission limit for HCl.

$$HCl = \sum_{i=1}^{n} \left[(C_{i90})(Q_i)(1.028)\right] \quad \text{(Eq. 9)}$$

Where:

HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.

C_{i90} = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 8 of this section.

Q_i = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Q_i.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

1.028 = Molecular weight ratio of HCl to chlorine.

(4) To demonstrate compliance with the applicable emission limit for TSM, the TSM emission rate that you calculate for your boiler or process heater using Equation 10 of this section must be less than the applicable emission limit for TSM.

$$TSM = \sum_{i=1}^{n} \left[(M_{i90})(Q_i)\right] \quad \text{(Eq. 10)}$$

Where:

TSM = TSM emission rate from the boiler or process heater in units of pounds per million Btu.

M_{i90} = 90th percentile confidence level concentration of TSM in fuel, i, in units of pounds per million Btu as calculated according to Equation 8 of this section.

Q_i = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of total selected metals. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Q_i.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.

(5) To demonstrate compliance with the applicable emission limit for mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 11 of this section must be less than the applicable emission limit for mercury.

$$\text{Mercury} = \sum_{i=1}^{n} \left[(HG_{i90})(Q_i)\right] \quad \text{(Eq. 11)}$$

Where:

Mercury = Mercury emission rate from the boiler or process heater in units of pounds per million Btu.

HG_{i90} = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 8 of this section.

Q_i = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Q_i.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest mercury content.

(e) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.7545(e).

Continuous Compliance Requirements

§63.7535 How do I monitor and collect data to demonstrate continuous compliance?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by §63.7505(d).

(b) Except for monitor malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must monitor continuously (or collect data at all required intervals) at all times that the affected source is operating.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, or required quality assurance or control activities in data averages and calculations used to report emission or operating levels You must use all the data collected during all other periods in assessing the operation of the control device and associated control system. Boilers and process heaters that have an applicable carbon monoxide work practice standard and are required to install and operate a CEMS, may not use data recorded during periods when the boiler or process heater is operating at less than 50 percent of its rated capacity.

§63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (10) of this section.

(1) Following the date on which the initial performance test is completed or is required to be completed under §§63.7 and 63.7510, whichever date comes first, you must not operate above any of the applicable maximum operating limits or below any of the applicable minimum operating limits listed in Tables 2 through 4 to this subpart at all times except during periods of startup, shutdown and malfunction. Operating limits do not apply during performance tests. Operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits.

(2) You must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would either result in lower emissions of TSM, HCl, and mercury, than the applicable emission limit for each pollutant (if you demonstrate compliance through fuel analysis), or result in lower fuel input of TSM, chlorine, and mercury than the maximum values calculated during the last performance tests (if you demonstrate compliance through performance testing).

(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis and you plan to burn a new type of fuel, you must recalculate the HCl emission rate using Equation 9 of §63.7530 according to paragraphs (a)(3)(i) through (iii) of this section.

(i) You must determine the chlorine concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.

(iii) Recalculate the HCl emission rate from your boiler or process heater under these new conditions using Equation 9 of §63.7530. The recalculated HCl emission rate must be less than the applicable emission limit.

(4) If you demonstrate compliance with an applicable HCl emission limit through performance testing and you plan to burn a new type of fuel type or a new mixture of fuels, you must recalculate the maximum chlorine input using Equation 5 of §63.7530. If the results of recalculating the maximum chlorine input using Equation 5 of §63.7530 are higher than the maximum chlorine input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the HCl emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(c).

(5) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the TSM emission rate using Equation 10 of §63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section.

(i) You must determine the TSM concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of TSM.

(iii) Recalculate the TSM emission rate from your boiler or process heater under these new conditions using Equation 10 of §63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.

(6) If you demonstrate compliance with an applicable TSM emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum TSM input using Equation 6 of §63.7530. If the results of recalculating the maximum total selected metals input using Equation 6 of §63.7530 are higher than the maximum TSM input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the TSM emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(c).

(7) If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the mercury emission rate using Equation 11 of §63.7530 according to the procedures specified in paragraphs (a)(7)(i) through (iii) of this section.

(i) You must determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of mercury.

(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 11 of §63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(8) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum mercury input using Equation 7 of §63.7530. If the results of recalculating the maximum mercury input using Equation 7 of §63.7530 are higher than the maximum mercury input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(c).

(9) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alarm and complete corrective actions according to your SSMP, and operate and maintain the fabric filter system such that the alarm does not sound more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alarm, the time corrective action was initiated and completed, and a brief description of the cause of the alarm and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the alarm sounds. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alarm time is counted. If corrective action is required, each alarm shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alarm time shall be counted as the actual amount of time taken to initiate corrective action.

(10) If you have an applicable work practice standard for carbon monoxide, and you are required to install a CEMS according to §63.7525(a), then you must meet the requirements in paragraphs (a)(10)(i) through (iii) of this section.

(i) You must continuously monitor carbon monoxide according to §§63.7525(a) and 63.7535.

(ii) Maintain a carbon monoxide emission level below your applicable carbon monoxide work practice standard in Table 1 to this subpart at all times except during periods of startup, shutdown, malfunction, and when your boiler or process heater is operating at less than 50 percent of rated capacity.

(iii) Keep records of carbon monoxide levels according to §63.7555(b).

(b) You must report each instance in which you did not meet each emission limit, operating limit, and work practice standard in Tables 1 through 4 to this subpart that apply to you. You must also report each instance during a startup, shutdown, or malfunction when you did not meet each applicable emission limit, operating limit, and work practice standard. These instances are deviations from the emission limits and work practice standards in this subpart. These deviations must be reported according to the requirements in §63.7550.

(c) During periods of startup, shutdown, and malfunction, you must operate in accordance with the SSMP as required in §63.7505(e).

(d) Consistent with §§63.6(e)and 63.7(e)(1), deviations that occur during a period of startup, shutdown, or malfunction are not violations if you demonstrate to the EPA Administrator's satisfaction that you were operating in accordance with your SSMP. The EPA Administrator will determine whether deviations that occur during a period of startup, shutdown, or malfunction are violations, according to the provisions in §63.6(e).

§63.7541 How do I demonstrate continuous compliance under the emission averaging provision?

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (4) of this section.

(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing large solid fuel boilers participating in the emissions averaging option as determined in §63.7522(f) and (g);

(2) For each existing solid fuel boiler participating in the emissions averaging option that is equipped with a dry control system, maintain opacity at or below the applicable limit;

(3) For each existing solid fuel boiler participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 3-hour average parameter values at or below the operating limits established during the most recent performance test; and

(4) For each existing solid fuel boiler participating in the emissions averaging option that has an approved alternative operating plan, maintain the 3-hour average parameter values at or below the operating limits established in the most recent performance test.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (4) of this section, except during periods of startup, shutdown, and malfunction, is a deviation.

Notification, Reports, and Records

§63.7545 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8 (e), (f)(4) and (6), and 63.9 (b) through (h) that apply to you by the dates specified.

(b) As specified in §63.9(b)(2), if you startup your affected source before November 12, 2004, you must submit an Initial Notification not later than 120 days after November 12, 2004. The Initial Notification must include the information required in paragraphs (b)(1) and (2) of this section, as applicable.

(1) If your affected source has an annual capacity factor of greater than 10 percent, your Initial Notification must include the information required by §63.9(b)(2).

(2) If your affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent such that the unit is in one of the limited use subcategories (the limited use solid fuel subcategory, the limited use liquid fuel subcategory, or the limited use gaseous fuel subcategory), your Initial Notification must include the information required by §63.9(b)(2) and also a signed statement indicating your affected source has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent.

(c) As specified in §63.9(b)(4) and (b)(5), if you startup your new or reconstructed affected source on or after November 12, 2004, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

(d) If you are required to conduct a performance test you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.

(e) If you are required to conduct an initial compliance demonstration as specified in §63.7530(a), you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For each initial compliance demonstration, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of the performance test and/or other initial compliance demonstrations according to §63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (9), as applicable.

(1) A description of the affected source(s) including identification of which subcategory the source is in, the capacity of the source, a description of the add-on controls used on the source description of the fuel(s) burned, and justification for the fuel(s) burned during the performance test.

(2) Summary of the results of all performance tests, fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits.

(3) Identification of whether you are complying with the particulate matter emission limit or the alternative total selected metals emission limit.

(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing or fuel analysis.

(5) Identification of whether you plan to demonstrate compliance by emissions averaging.

(6) A signed certification that you have met all applicable emission limits and work practice standards.

(7) A summary of the carbon monoxide emissions monitoring data and the maximum carbon monoxide emission levels recorded during the performance test to show that you have met any applicable work practice standard in Table 1 to this subpart.

(8) If your new or reconstructed boiler or process heater is in one of the liquid fuel subcategories and burns only liquid fossil fuels other than residual oil either alone or in combination with gaseous fuels, you must submit a signed statement certifying this in your Notification of Compliance Status report.

(9) If you had a deviation from any emission limit or work practice standard, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.

§63.7550 What reports must I submit and when?

(a) You must submit each report in Table 9 to this subpart that applies to you.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.7495 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in §63.7495.

(2) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.7495.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each affected source that is subject to permitting regulations pursuant to 40 CFR part 70 or 40 CFR part 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (11) of this section.

(1) Company name and address.

(2) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel and the total fuel usage amount with units of measure.

(5) A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during this test, if applicable.

(6) A signed statement indicating that you burned no new types of fuel. Or, if you did burn a new type of fuel, you must submit the calculation of chlorine input, using Equation 5 of §63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 9 of §63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel, you must submit the calculation of TSM input, using Equation 6 of §63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate using Equation 10 of §63.7530 that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel, you must submit the calculation of mercury input, using Equation 7 of §63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 11 of §63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).

(7) If you wish to burn a new type of fuel and you can not demonstrate compliance with the maximum chlorine input operating limit using Equation 5 of §63.7530, the maximum TSM input operating limit using Equation 6 of §63.7530, or the maximum mercury input operating limit using Equation 7 of §63.7530, you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.

(8) The hours of operation for each boiler and process heater that is subject to an emission limit for each calendar month within the semiannual reporting period. This requirement applies only to limited use boilers and process heaters.

(9) If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your SSMP, the compliance report must include the information in §63.10(d)(5)(i).

(10) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, and there are no deviations from the requirements for work practice standards in this subpart, a statement that there were no deviations from the emission limits, operating limits, or work practice standards during the reporting period.

(11) If there were no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in §63.8(c)(7), a statement that there were no periods during which the CMSs were out of control during the reporting period.

(d) For each deviation from an emission limit or operating limit in this subpart and for each deviation from the requirements for work practice standards in this subpart that occurs at an affected source where you are not using a CMSs to comply with that emission limit, operating limit, or work practice standard, the compliance report must contain the information in paragraphs (c)(1) through (10) of this section and the information required in paragraphs (d)(1) through (4) of this section. This includes periods of startup, shutdown, and malfunction.

(1) The total operating time of each affected source during the reporting period.

(2) A description of the deviation and which emission limit, operating limit, or work practice standard from which you deviated.

(3) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(4) A copy of the test report if the annual performance test showed a deviation from the emission limit for particulate matter or the alternative TSM limit, a deviation from the HCl emission limit, or a deviation from the mercury emission limit.

(e) For each deviation from an emission limitation and operating limit or work practice standard in this subpart occurring at an affected source where you are using a CMS to comply with that emission limit, operating limit, or work practice standard, you must include the information in paragraphs (c) (1) through (10) of this section and the information required in paragraphs (e) (1) through (12) of this section. This includes periods of startup, shutdown, and malfunction and any deviations from your site-specific monitoring plan as required in §63.7505(d).

(1) The date and time that each malfunction started and stopped and description of the nature of the deviation (*i.e.*, what you deviated from).

(2) The date and time that each CMS was inoperative, except for zero (low level) and high-level checks.

(3) The date, time, and duration that each CMS was out of control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to startup, shutdown, control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMSs downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.

(8) An identification of each parameter that was monitored at the affected source for which there was a deviation, including opacity, carbon monoxide, and operating parameters for wet scrubbers and other control devices.

(9) A brief description of the source for which there was a deviation.

(10) A brief description of each CMS for which there was a deviation.

(11) The date of the latest CMS certification or audit for the system for which there was a deviation.

(12) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 40 CFR part 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table

9 to this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. However, submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you operate a new gaseous fuel unit that is subject to the work practice standard specified in Table 1 to this subpart, and you intend to use a fuel other than natural gas or equivalent to fire the affected unit, you must submit a notification of alternative fuel use within 48 hours of the declaration of a period of natural gas curtailment or supply interruption, as defined in §63.7575. The notification must include the information specified in paragraphs (g)(1) through (5) of this section.

(1) Company name and address.

(2) Identification of the affected unit.

(3) Reason you are unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.

(4) Type of alternative fuel that you intend to use.

(5) Dates when the alternative fuel use is expected to begin and end.

§63.7555 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) through (3) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in §63.10(b)(2)(xiv).

(2) The records in §63.6(e)(3)(iii) through (v) related to startup, shutdown, and malfunction.

(3) Records of performance tests, fuel analyses, or other compliance demonstrations, performance evaluations, and opacity observations as required in §63.10(b)(2)(viii).

(b) For each CEMS, CPMS, and COMS, you must keep records according to paragraphs (b)(1) through (5) of this section.

(1) Records described in §63.10(b)(2)(vi) through (xi).

(2) Monitoring data for continuous opacity monitoring system during a performance evaluation as required in §63.6(h)(7)(i) and (ii).

(3) Previous (*i.e.*, superseded) versions of the performance evaluation plan as required in §63.8(d)(3).

(4) Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i).

(5) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

(c) You must keep the records required in Table 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits such as opacity, pressure drop, carbon monoxide, and pH to show continuous compliance with each emission limit, operating limit, and work practice standard that applies to you.

(d) For each boiler or process heater subject to an emission limit, you must also keep the records in paragraphs (d)(1) through (5) of this section.

(1) You must keep records of monthly fuel use by each boiler or process heater, including the type(s) of fuel and amount(s) used.

(2) You must keep records of monthly hours of operation by each boiler or process heater. This requirement applies only to limited-use boilers and process heaters.

(3) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 5 of §63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 9 of §63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.

(4) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 6 of §63.7530, that were done to demonstrate continuous compliance with the TSM emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of TSM emission rates, using Equation 10 of §63.7530, that were done to demonstrate compliance with the TSM emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum TSM fuel input or TSM emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate TSM fuel input, or TSM emission rates, for each boiler and process heater.

(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 7 of §63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury emission rates, using Equation 11 of §63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.

(e) If your boiler or process heater is subject to an emission limit or work practice standard in Table 1 to this subpart and has a federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent such that the unit is in one of the limited use subcategories, you must keep the records in paragraphs (e)(1) and (2) of this section.

(1) A copy of the federally enforceable permit that limits the annual capacity factor of the source to less than or equal to 10 percent.

(2) Fuel use records for the days the boiler or process heater was operating.

§63.7560 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). You can keep the records off site for the remaining 3 years.

Other Requirements and Information

§63.7565 What parts of the General Provisions apply to me?

Table 10 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

§63.7570 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (5) of this section are retained by the EPA Administrator and are not transferred to the State, local, or tribal agency, however, the U.S. EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in §63.7500(a) and (b) under §63.6(g).

(2) Approval of alternative opacity emission limits in §63.7500(a) under §63.6(h)(9).

(3) Approval of major change to test methods in Table 5 to this subpart under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(4) Approval of major change to monitoring under §63.8(f) and as defined in §63.90.

(5) Approval of major change to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

§63.7575 What definitions apply to this subpart?

Terms used in this subpart are defined in the CAA, in §63.2 (the General Provisions), and in this section as follows:

Annual capacity factor means the ratio between the actual heat input to a boiler or process heater from the fuels burned during a calendar year, and the potential heat input to the boiler or process heater had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.

Bag leak detection system means an instrument that is capable of monitoring particulate matter loadings in the exhaust of a fabric filter (*i.e.*, baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative particulate matter loadings.

Biomass fuel means unadulterated wood as defined in this subpart, wood residue, and wood products (*e.g.*, trees, tree stumps, tree limbs, bark, lumber, sawdust, sanderdust, chips, scraps, slabs, millings, and shavings); animal litter; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (*e.g.*, almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds.

Blast furnace gas fuel-fired boiler or process heater means an industrial/commercial/ institutional boiler or process heater that receives 90 percent or more of its total heat input (based on an annual average) from blast furnace gas.

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Waste heat boilers are excluded from this definition.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials in ASTM D388–991 \1\, "Standard Specification for Classification of Coals by Rank \1\" (incorporated by reference, see §63.14(b)), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures, for the purposes of this subpart. Coal derived gases are excluded from this definition.

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (6,000 Btu per pound) on a dry basis.

Commercial/institutional boiler means a boiler used in commercial establishments or institutional establishments such as medical centers, research centers, institutions of higher education, hotels, and laundries to provide electricity, steam, and/or hot water.

Construction/demolition material means waste building material that result from the construction or demolition operations on houses and commercial and industrial buildings.

Deviation. (1) Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(iii) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless or whether or not such failure is permitted by this subpart.

(2) A deviation is not always a violation. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.

Distillate oil means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D396–02a, "Standard Specifications for Fuel Oils 1" (incorporated by reference, see §63.14(b)).

Dry scrubber means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems in fluidized bed boilers and process heaters are included in this definition.

Electric utility steam generating unit means a fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale is considered an electric utility steam generating unit.

Electrostatic precipitator means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper.

Fabric filter means an add-on air pollution control device used to capture particulate matter by filtering gas streams through filter media, also known as a baghouse.

Federally enforceable means all limitations and conditions that are enforceable by the EPA Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Firetube boiler means a boiler in which hot gases of combustion pass through the tubes and water contacts the outside surfaces of the tubes.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, sub-bituminous coal, lignite, anthracite, biomass, construction/demolition material, salt water laden wood, creosote treated wood, tires, residual oil. Individual fuel types received from different suppliers are not considered new fuel types except for construction/ demolition material.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas is exempted from this definition.

Heat input means heat derived from combustion of fuel in a boiler or process heater and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.

Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous or liquid fuel and is withdrawn for use external to the vessel at pressures not exceeding 160 psig, including the apparatus by which the heat is generated and all controls and devices necessary to prevent water temperatures from exceeding 210°F (99°C).

Industrial boiler means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.

Large gaseous fuel subcategory includes any watertube boiler or process heater that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment or gas supply emergencies, has a rated capacity of greater than 10 MMBtu per hour heat input, and has an annual capacity factor of greater than 10 percent.

Large liquid fuel subcategory includes any watertube boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has an annual capacity factor of greater than 10 percent. Large gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in this definition.

Large solid fuel subcategory includes any watertube boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has an annual capacity factor of greater than 10 percent.

Limited use gaseous fuel subcategory includes any watertube boiler or process heater that burns gaseous fuels not combined with any liquid or solid fuels, burns liquid fuel only during periods of gas curtailment or gas supply emergencies, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent.

Limited use liquid fuel subcategory includes any watertube boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent. Limited use gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in this definition.

Limited use solid fuel subcategory includes any watertube boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent.

Liquid fossil fuel means petroleum, distillate oil, residual oil and any form of liquid fuel derived from such material.

Liquid fuel includes, but is not limited to, distillate oil, residual oil, waste oil, and process liquids.

Minimum pressure drop means 90 percent of the lowest test-run average pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum scrubber effluent pH means 90 percent of the lowest test-run average effluent pH measured at the outlet of the wet scrubber according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable hydrogen chloride emission limit.

Minimum scrubber flow rate means 90 percent of the lowest test-run average flow rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum sorbent flow rate means 90 percent of the lowest test-run average sorbent (or activated carbon) flow rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

Minimum voltage or amperage means 90 percent of the lowest test-run average voltage or amperage to the electrostatic precipitator measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquid petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835–03a, "Standard Specification for Liquid Petroleum Gases" (incorporated by reference, see §63.14(b)).

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Particulate matter means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an alternative method.

Period of natural gas curtailment or supply interruption means a period of time during which the supply of natural gas to an affected facility is halted for reasons beyond the control of the facility. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment or supply interruption.

Process heater means an enclosed device using controlled flame, that is not a boiler, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not directly come into contact with process materials. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves.

Residual oil means crude oil, and all fuel oil numbers 4, 5 and 6, as defined by the American Society for Testing and Materials in ASTM D396–02a, "Standard Specifications for Fuel Oils [1]" (incorporated by reference, see §63.14(b)).

Responsible official means responsible official as defined in 40 CFR 70.2.

Small gaseous fuel subcategory includes any firetube boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment or gas supply emergencies, and any boiler or process heater that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment or gas supply emergencies, and has a rated capacity of less than or equal to 10 MMBtu per hour heat input.

Small liquid fuel subcategory includes any firetube boiler that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, and any boiler or process heater that does not burn any solid fuel and burns any liquid fuel either alone or in combination with gaseous fuels, and has a rated capacity of less than or equal to 10 MMBtu per hour heat input. Small gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies are not included in this definition.

Small solid fuel subcategory includes any firetube boiler that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels, and any other boiler or process heater that burns any amount of solid fuel either alone or in combination with liquid or gaseous fuels and has a rated capacity of less than or equal to 10 MMBtu per hour heat input.

Solid fuel includes, but is not limited to, coal, wood, biomass, tires, plastics, and other nonfossil solid materials.

Temporary boiler means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another. A temporary boiler that remains at a location for more than 180 consecutive days is no longer considered to be a temporary boiler. Any temporary boiler that replaces a temporary boiler at a location and is intended to perform the same or similar function will be included in calculating the consecutive time period.

Total selected metals means the combination of the following metallic HAP: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

Unadulterated wood means wood or wood products that have not been painted, pigment-stained, or pressure treated with compounds such as chromate copper arsenate, pentachlorophenol, and creosote. Plywood, particle board, oriented strand board, and other types of wood products bound by glues and resins are included in this definition.

Waste heat boiler means a device that recovers normally unused energy and converts it to usable heat. Waste heat boilers incorporating duct or supplemental burners that are designed to supply 50 percent or more of the total rated heat input capacity of the waste heat boiler are not considered waste heat boilers, but are considered boilers. Waste heat boilers are also referred to as heat recovery steam generators.

Watertube boiler means a boiler in which water passes through the tubes and hot gases of combustion pass over the outside surfaces of the tubes.

Wet scrubber means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler or process heater to control emissions of particulate matter and/or to absorb and neutralize acid gases, such as hydrogen chloride.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the CAA.

Tables to Subpart DDDDD of Part 63

TABLE 1 TO SUBPART DDDDD OF PART 63.—EMISSION LIMITS AND WORK PRACTICE STANDARDS

As stated in §63.7500, you must comply with the following applicable emission limits and work practice standards:

If your boiler or process heater is in this subcategory…	For the following pollutants…	You must meet the following emission limits and work practice standards…
1. New or reconstructed large solid fuel	a. Particulate Matter (or Total Selected Metals)	0.025 lb per MMBtu of heat input; or (0.0003 lb per MMBtu of heat input).
	b. Hydrogen Chloride	0.02 lb per MMBtu of heat input.
	c. Mercury	0.000003 lb per MMBtu of heat input.
	d. Carbon Monoxide	400 ppm by volume on a dry basis corrected to 7 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
2. New or reconstructed limited use solid fuel	a. Particulate Matter (or Total Selected Metals)	0.025 lb per MMBtu of heat input; or (0.0003 lb per MMBtu of heat input).
	b. Hydrogen Chloride	0.02 lb per MMBtu of heat input.
	c. Mercury	0.000003 lb per MMBtu of heat input.
	d. Carbon Monoxide	400 ppm by volume on a dry basis corrected to 7 percent oxygen (3-run average).
3. New or reconstructed small solid fuel	a. Particulate Matter (or Total Selected Metals)	0.025 lb per MMBtu of heat input; or (0.0003 lb per MMBtu of heat input).
	b. Hydrogen Chloride	0.02 lb per MMBtu of heat input.
	c. Mercury	0.000003 lb per MMBtu of heat input.
4. New reconstructed large liquid fuel	a. Particulate Matter	0.03 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.0005 lb per MMBtu of heat input.
	c. Carbon Monoxide	400 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
5. New or reconstructed limited use liquid fuel	a. Particulate Matter	0.03 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.0009 lb per MMBtu of heat input.
	c. Carbon Monoxide	400 ppm by volume on a dry basis liquid corrected to 3 percent oxygen (3-run average).
6. New or reconstructed small liquid fuel	a. Particulate Matter	0.03 lb per MMBtu of heat input.
	b. Hydrogen Chloride	0.0009 lb per MMBtu of heat input.
7. New reconstructed large gaseous fuel	Carbon Monoxide	400 ppm by volume on a dry basis corrected to 3 percent oxygen (30-day rolling average for units 100 MMBtu/hr or greater, 3-run average for units less than 100 MMBtu/hr).
8. New or reconstructed limited use gaseous fuel	Carbon Monoxide	400 ppm by volume on a dry basis corrected to 3 percent oxygen (3-run average).
9. Existing large solid fuel	a. Particulate Matter (or Total Selected Metals)	0.07 lb per MMBtu of heat input; or (0.001 lb per MMBtu of heat input).
	b. Hydrogen Chloride	0.09 lb per MMBtu of heat input.
	c. Mercury	0.000009 lb per MMBtu of heat input.
10. Existing limited use solid fuel	Particulate Matter (or Total Selected Metals)	0.21 lb per MMBtu of heat input; or (0.004 lb per MMBtu of heat input).

TABLE 2 TO SUBPART DDDDD OF PART 63. — OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS WITH PARTICULATE MATTER EMISSION LIMITS

As stated in §63.7500, you must comply with the applicable operating limits:

If you demonstrate compliance with applicable particulate matter emission limits using…	You must meet these operating limits…
1. Wet scrubber control	a. Maintain the minimum pressure drop and liquid flow-rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.
2. Fabric filter control	a. Install and operate a bag leak detection system according to §63.7525 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during each 6-month period; or
	b. This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).
3. Electrostatic precipitator control	a. This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average); or
	b. This option is only for boilers and process heaters that operate additional wet control systems. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for particulate matter.
4. Any other control type	This option is for boilers and process heaters that operate dry control systems. Existing boilers and process heaters must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).

TABLE 3 TO SUBPART DDDDD OF PART 63. — OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS WITH MERCURY EMISSION LIMITS AND BOILERS AND PROCESS HEATERS THAT CHOOSE TO COMPLY WITH THE ALTERNATIVE TOTAL SELECTED METALS EMISSION LIMITS

As stated in §63 7500, you must comply with the applicable operating limits:

If you demonstrate compliance with applicable mercury and/or total selected metals emission limits using…	You must meet these operating limits…
1. Wet scrubber control	Maintain the minimum pressure drop and liquid flow-rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limits for mercury and/or total selected metals.
2. Fabric filter control	a. Install and operate a bag leak detection system according to §63.7525 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during a 6-month period; or
	b. This option is for boilers and process heaters that operate dry control systems. Existing sources must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New sources must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).
3. Electrostatic precipitator control	a. This option is for boilers and process heaters that operate dry control systems. Existing sources must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New sources must maintain opacity to less than or equal to 10 percent opacity (1-hour block average); or
	b. This option is only for boilers and process heaters that operate additional wet control systems. Maintain the minimum voltage and secondary current or total power input of the electrostatic precipitator at or above the operating limits established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limits for mercury and/or total selected metals.
4. Dry scrubber or carbon injection control	Maintain the minimum sorbent or carbon injection rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for mercury.
5. Any other control type	This option is only for boilers and process heaters that operate dry control systems. Existing sources must maintain opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent. New sources must maintain opacity to less than or equal to 10 percent opacity (1-hour block average).
6. Fuel analysis	Maintain the fuel type or fuel mixture such that the mercury and/or total selected metals emission rates calculated according to §63.7530(d)(4) and/or (5) is less than the applicable emission limits for mercury and/or total selected metals.

TABLE 4 TO SUBPART DDDDD OF PART 63. — OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS WITH HYDROGEN CHLORIDE EMISSION LIMITS

As stated in §63.7500, you must comply with the following applicable operating limits:

If you demonstrate compliance with applicable hydrogen chloride emission limits using…	You must meet these operating limits…
1. Wet scrubber control	Maintain the minimum scrubber effluent pH, pressure drop, and liquid flow-rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for hydrogen chloride.
2. Dry scrubber control	Maintain the minimum sorbent injection rate at or above the operating levels established during the performance test according to §63.7530(c) and Table 7 to this subpart that demonstrated compliance with the applicable emission limit for hydrogen chloride.
3. Fuel analysis	Maintain the fuel type or fuel mixture such that the hydrogen chloride emission rate calculated according to §63.7530(d)(3) is less than the applicable emission limit for hydrogen chloride.

TABLE 5 TO SUBPART DDDDD OF PART 63. — PERFORMANCE TESTING REQUIREMENTS

As stated in §63.7520, you must comply with the following requirements for performance test for existing, new or reconstructed affected sources:

To conduct a performance test for the following pollutant…	You must…	Using…
1. Particulate Matter	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see §63.14(i)).
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the particulate matter emission concentration.	Method 5 or 17 (positive pressure fabric filters must use Method 5D) in appendix A to part 60 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
2. Total selected metals	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see §63.14(i)).
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the total selected metals emission concentration.	Method 29 in appendix A to part 60 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
3. Hydrogen Chloride	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see §63.14(i)).
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	e. Measure the hydrogen chloride emission concentration.	Method 26 or 26A in appendix A to part 60 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
4. Mercury	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASME PTC 19, Part 10 (1981) (IBR, see §62.14(i)).
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.

To conduct a performance test for the following pollutant…	You must…	Using…
	e. Measure the mercury emission concentration.	Method 29 in appendix A to part 60 of this chapter or Method 101A in appendix B to part 61 of this chapter or ASTM Method D6784–02 (IBR, see §63.14(b)).
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.
5. Carbon Monoxide	a. Select the sampling ports location and the number of traverse points.	Method 1 in appendix A to part 60 of this chapter.
	b. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A to part 60 of this chapter, or ASTM D6522–00 (IBR, see §63.14(b)), or ASME PTC 19, Part 10 (1981) (IBR, see §63.14(i)).
	c. Measure the moisture content of the stack gas.	Method 4 in appendix A to part 60 of this chapter.
	d. Measure the carbon monoxide emission concentration.	Method 10, 10A, or 10B in appendix A to part 60 of this chapter, or ASTM D6522–00 (IBR, see §63.14(b)) when the fuel is natural gas.

TABLE 6 TO SUBPART DDDDD OF PART 63.—FUEL ANALYSIS REQUIREMENTS

As stated in §63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources:

To conduct a performance test for the following pollutant…	You must…	Using…
1. Mercury	a. Collect fuel samples	Procedure in §63.7521(c) or ASTM D2234–00 \1\ (for coal)(IBR, see §63.14(b)) or ASTM D6323–98 (2003)(for biomass)(IBR, see §63.14(b)) or equivalent.
	b. Composite fuel samples	Procedure in §63.7521(d) or equivalent.
	c. Prepare composited fuel sample	SW–846–3050B (for solid samples) or SW– 846–3020A (for liquid samples) or ASTM D2013–01 (for coal) (IBR, see §63.14(b)) or ASTM D5198–92 (2003) (for bio-mass)(IBR, see §63.14(b)) or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865–03a (for coal)(IBR, see §63.14(b)) or ASTM E711–87 (1996) (for biomass)(IBR, see §63.14(b)) or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173–02 (IBR, see §63.14(b)) or ASTM E871–82 (1998)(IBR, see §63.14(b)) or equivalent.
	f. Measure mercury concentration in fuel sample.	ASTM D3684–01 (for coal)(IBR, see §63.14(b)) or SW–846–7471A (for solid samples) or SW–846 7470A (for liquid samples).
	g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content.	
2. Total selected metals	a. Collect fuel samples.	Procedure in §63.7521(c) or ASTM D2234–00 \1\ (for coal)(IBR, see §63.14(b)) or ASTM D6323–98 (2003) (for biomass)(IBR, see §63.14(b)) or equivalent.
	b. Composite fuel samples	Procedure in §63.7521(d) or equivalent.
	c. Prepare composited fuel samples	SW–846–3050B (for solid samples) or SW– 846–3020A (for liquid samples) or ASTM D2013–01 (for coal)(IBR, see §63.14(b)) or ASTM D5198–92 (2003)(for biomass)(IBR, see §63.14(b)) or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865–03a (for coal)(IBR, see §63.14(b)) or ASTM E 711–87 (for bio-mass)(IBR, see §63.14(b)) or equivalent
	e. Determine moisture content of the fuel type	ASTM D3173–02 (IBR, see §63.14(b)) or ASTM E871 (IBR, see §63.14(b)) or equivalent.
	f. Measure total selected metals concentration in fuel sample.	SW–846–6010B or ASTM D3683–94 (2000) (for coal) (IBR, see §63.14(b)) or ASTM E885–88 (1996) (for biomass)(IBR, see §63.14(b)).
	g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content.	
3. Hydrogen chloride	a. Collect fuel samples	Procedure in §63.7521(c) or ASTM D2234–00 \1\ (for coal)(IBR, see §63.14(b)) or ASTM D6323–98 (2003) (for biomass)(IBR, see §63.14(b)) or equivalent.
	b. Composite fuel samples	Procedure in §63.7521(d) or equivalent.

To conduct a performance test for the following pollutant…	You must…	Using…
	c. Prepare composited fuel samples	SW–846–3050B (for solid samples) or SW– 846–3020A (for liquid samples) or ASTM D2013–01 (for coal)(IBR, see §63.14(b)) or ASTM D5198–92 (2003) (for biomass) (IBR, see §63.14(b)) or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865–03a (for coal)(IBR, see §63.14(b)) or ASTM E711–87 (1996) (for biomass)(IBR, see §63.14(b)) or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173–02 (IBR, see §63.14(b)) or ASTM E871–82 (1998)(IBR, see §63.14(b)) or equivalent.
	f. Measure chlorine concentration in fuel sample.	SW-846-9250 or ASTM E776-87 (1996) (for biomass) (IBR, see §63.14(b)) or equivalent.
	g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content.	

TABLE 7 TO SUBPART DDDDD OF PART 63. — ESTABLISHING OPERATING LIMITS

As stated in §63.7520, you must comply with the following requirements for establishing operating limits:

If you have an applicable emission limit for	And your operating limits are based on…	You must…	Using…	According to the following requirements…
1. Particulate matter, mercury, or total selected metals.	a. Wet scrubber operating parameters.	i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to §63.7530(c).	(1) Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test.	(a) You must collect pressure drop and liquid flow-rate data every 15 minutes during the entire period of the performance tests;
				(b) Determine the average pressure drop and liquid flow-rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.
	b. Electrostatic precipitator operating parameters (option only for units with additional wet scrubber control).	i. Establish a site-specific minimum voltage and secondary current or total power input according to §63.7530(c).	(1) Data from the pressure drop and liquid flow rate monitors and the particulate matter, mercury, or total selected metals performance test.	(a) You must collect voltage and secondary current or total power input data every 15 minutes during the entire period of the performance tests;
				(b) Determine the average voltage and secondary current or total power input for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.
2. Hydrogen Chloride.	a. Wet scrubber operating parameters.	i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to §63.7530(c).	(1) Data from the pH, pressure drop, and liquid flow-rate monitors and the hydrogen chloride performance test.	(a) You must collect pH, pressure drop, and liquid flow-rate data every 15 minutes during the entire period of the performance tests;
				(b) Determine the average pH, pressure drop, and liquid flow-rate for each individual test run in the three-run performance test by computing the average of all the 15-minute readings taken during each test run.
	b. Dry scrubber operating parameters.	i. Establish a site-specific minimum sorbent injection rate operating limit according to §63.7530(c).	(1) Data from the sorbent injection rate monitors and hydrogen chloride performance test.	(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests;
				(b) Determine the average sorbent injection rate for each individual test run in the three-run performance test by computing the average of all the 15 minute readings taken during each test run.

TABLE 8 TO SUBPART DDDDD OF PART 63. — DEMONSTRATING CONTINUOUS COMPLIANCE

As stated in §63.7540, you must show continuous compliance with the emission limitations for affected sources according to the following:

If you must meet the following operating limits or work practice standards...	You must demonstrate continuous compliance by...
1. Opacity	a. Collecting the opacity monitoring system data according to §§63.7525(b) and 63.7535; and b. Reducing the opacity monitoring data to 6-minute averages; and c. Maintaining opacity to less than or equal to 20 percent (6-minute average) except for one 6-minute period per hour of not more than 27 percent for existing sources; or maintaining opacity to less than or equal to 10 percent (1-hour block average) for new sources.
2. Fabric Filter Bag Leak Detection Operation	Installing and operating a bag leak detection system according to §63.7525 and operating the fabric filter such that the requirements in §63.7540(a)(9) are met.
3. Wet Scrubber Pressure Drop and Liquid Flow-rate	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§63.7525 and 63.7535; and b. Reducing the data to 3-hour block averages; and c. Maintaining the 3-hour average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to §63.7530(c).
4. Wet Scrubber pH	a. Collecting the pH monitoring system data according to §§63.7525 and 63.7535; and b. Reducing the data to 3-hour block averages; and c. Maintaining the 3-hour average pH at or above the operating limit established during the performance test according to §63.7530(c).
5. Dry Scrubber Sorbent or Carbon Injection Rate	a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§63.7525 and 63.7535; and b. Reducing the data to 3-hour block averages; and c. Maintaining the 3-hour average sorbent or carbon injection rate at or above the operating limit established during the performance test according to §§63 7530(c).
6. Electrostatic Precipitator Secondary Current and Voltage or Total Power Input	a. Collecting the secondary current and voltage or total power input monitoring system data for the electrostatic precipitator according to §§63.7525 and 63.7535; and b. Reducing the data to 3-hour block averages; and c. Maintaining the 3-hour average secondary current and voltage or total power input at or above the operating limits established during the performance test according to §§63.7530(c).
7. Fuel Pollutant Content	a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to §63.7530(c) or (d) as applicable; and b. Keeping monthly records of fuel use according to §63.7540(a).

TABLE 9 TO SUBPART DDDDD OF PART 63. — REPORTING REQUIREMENTS

As stated in §63.7550, you must comply with the following requirements for reports:

You must submit a(n)	The report must contain . . .	You must submit the report...
1. Compliance report	a. Information required in §63.7550(c)(1) through (11); and b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 8 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in §63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and c. If you have a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain the information in §63.7550(d). If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control, as specified in §63.8(c)(7), the report must contain the information in §63.7550(e); and d. If you had a startup, shutdown, or malfunction during the reporting period and you took actions consistent with your startup, shutdown, and malfunction plan, the compliance report must include the information in §63.10(d)(5)(i)	Semiannually according to the requirements in §63.7550(b)

You must submit a(n)	The report must contain . . .	You must submit the report...
2. An immediate startup, shutdown, and malfunction report if you had a startup, shutdown, or malfunction during the reporting period that is not consistent with your startup, shutdown, and malfunction plan, and the source exceeds any applicable emission limitation in the relevant emission standard.	a. Actions taken for the event; and b. The information in §63.10(d)(5)(ii)	i. By fax or telephone within 2 working days after starting actions inconsistent with the plan; and ii. By letter within 7 working days after the end of the event unless you have made alternative arrangements with the permitting authority.

TABLE 10 TO SUBPART DDDDD OF PART 63. — APPLICABILITY OF GENERAL PROVISIONS TO SUBPART DDDDD

As stated in §63.7565, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Brief description	Applicable
§63.1	Applicability	Initial Applicability Determination; Applicability After Standard Established; Permit Requirements; Extensions, Notifications.	Yes.
§63.2	Definitions	Definitions for part 63 standards.	Yes.
§63.3	Units and Abbreviations	Units and abbreviations for part 63 standards.	Yes.
§63.4	Prohibited Activities	Prohibited Activities; Compliance date; Circumvention, Severability.	Yes.
§63.5	Construction/Reconstruction	Applicability; applications; approvals.	Yes.
§63.6(a)	Applicability	GP apply unless compliance extension; and GP apply to area sources that become major.	Yes.
§63.6(b)(1)–(4)	Compliance Dates for New and Reconstructed sources	Standards apply at effective date; 3 years after effective date; upon startup; 10 years after construction or reconstruction commences for 112(f).	Yes.
§63.6(b)(5)	Notification	Must notify if commenced construction or reconstruction after proposal.	Yes.
§63.6(b)(6)	[Reserved]		
§63.6(b)(7)	Compliance Dates for New and Reconstructed Area Sources That Become Major	Area sources that become major must comply with major source standards immediately upon becoming major, regardless of whether required to comply when they were an area source.	Yes.
§63.6(c)(1)–(2)	Compliance Dates for Existing Sources	Comply according to date in subpart, which must be no later than 3 years after effective date; and for 112(f) standards, comply within 90 days of effective date unless compliance extension.	Yes.
§63.6(c)(3)–(4)	[Reserved]		
§63.6(c)(5)	Compliance Dates for Existing Area Sources That Become Major.	Area sources that become major must comply with major source standards by date indicated in subpart or by equivalent time period (for example, 3 years).	Yes.
§63.6(d)	[Reserved].		
§63.6(e)(1)–(2)	Operation & Maintenance	Operate to minimize emissions at all times; and Correct malfunctions as soon as practicable; and Operation and maintenance requirements independently enforceable; information Administrator will use to determine if operation and maintenance requirements were met.	Yes.
§63.6(e)(3)	Startup, Shutdown, and Malfunction Plan (SSMP).	Requirement for SSM and startup, shutdown, malfunction plan; and content of SSMP.	Yes.
§63.6(f)(1)	Compliance Except During SSM	Comply with emission standards at all times except during SSM.	Yes.
§63.6(f)(2)–(3)	Methods for Determining Compliance	Compliance based on performance test, operation and maintenance plans, records, inspection.	Yes.
§63.6(g)(1)–(3)	Alternative Standard	Procedures for getting an alternative standard.	Yes.
§63.6(h)(1)	Compliance with Opacity/VE Standards	Comply with opacity/VE emission limitations at all times except during SSM.	Yes.
§63.6(h)(2)(i)	Determining Compliance with Opacity/ Visible Emission (VE) Standards.	If standard does not state test method, use Method 9 for opacity and Method 22 for VE.	No.
§63.6(h)(2)(ii)	[Reserved].		
§63.6(h)(2)(iii)	Using Previous Tests to Demonstrate Compliance with Opacity/VE Standards	Criteria for when previous opacity/VE testing can be used to show compliance with this subpart.	Yes.
§63.6(h)(3)	[Reserved].		

Citation	Subject	Brief description	Applicable
§63.6(h)(4)	Notification of Opacity/VE Observation Date.	Notify Administrator of anticipated date of observation.	No.
§63.6(h)(5)(i),(iii)–(v)	Conducting Opacity/VE Observations	Dates and Schedule for conducting opacity/VE observations.	No.
§63.6(h)(5)(ii)	Opacity Test Duration and Averaging Times.	Must have at least 3 hours of observation with thirty, 6-minute averages.	No.
§63.6(h)(6)	Records of Conditions During Opacity/VE observations.	Keep records available and allow Administrator to inspect.	No.
§63.6(h)(7)(i)	Report continuous opacity monitoring system Monitoring Data from Performance Test.	Submit continuous opacity monitoring system data with other performance test data.	Yes.
§63.6(h)(7)(ii)	Using continuous opacity monitoring system instead of Method 9.	Can submit continuous opacity monitoring system data instead of Method 9 results even if subpart requires Method 9, but must notify Administrator before performance test.	No.
§63.6(h)(7)(iii)	Averaging time for continuous opacity monitoring system during performance test.	To determine compliance, must reduce continuous opacity monitoring system data to 6-minute averages.	Yes.
§63.6(h)(7)(iv)	Continuous opacity monitoring system requirements.	Demonstrate that continuous opacity monitoring system performance evaluations are conducted according to §§63.8(e), continuous opacity monitoring systems are properly maintained and operated according to §63.8(c) and data quality as §63.8(d).	Yes.
§63.6(h)(7)(v)	Determining Compliance with Opacity/VE Standards.	Continuous opacity monitoring system is probative but not conclusive evidence of compliance with opacity standard, even if Method 9 observation shows otherwise. Requirements for continuous opacity monitoring system to be probative evidence-proper maintenance, meeting PS 1, and data have not been altered.	Yes.
§63.6(h)(8)	Determining Compliance with Opacity/VE Standards.	Administrator will use all continuous opacity monitoring system, Method 9, and Method 22 results, as well as information about operation and maintenance to determine compliance.	Yes.
§63.6(h)(9)	Adjusted Opacity Standard	Procedures for Administrator to adjust an opacity standard.	Yes.
§63.6(i)(1)–(14)	Compliance Extension	Procedures and criteria for Administrator to grant compliance extension.	Yes.
§63.6(j)	Presidential Compliance Exemption.	President may exempt source category from requirement to comply with rule.	Yes
§63.7(a)(1)	Performance Test Dates	Dates for conducting Initial Performance Testing and Other Compliance Demonstrations.	Yes.
§63.7(a)(2)	Performance Test Dates	New source with initial startup date before effective date has 180 days after effective date to demonstrate compliance	Yes
§63.7(a)(2)(ii–viii)	[Reserved].		
§63.7(a)(2)(ix)	Performance Test Dates	1. New source that commenced construction between proposal and promulgation dates, when promulgated standard is more stringent than proposed standard, has 180 days after effective date or 180 days after startup of source, whichever is later, to demonstrate compliance; and,	Yes.
		2. If source initially demonstrates compliance with less stringent proposed standard, it has 3 years and 180 days after the effective date of the standard or 180 days after startup of source, whichever is later, to demonstrate compliance with promulgated standard.	No.
§63.7(a)(3)	Section 114 Authority	Administrator may require a performance test under CAA Section 114 at any time.	Yes.
§63.7(b)(1)	Notification of Performance Test	Must notify Administrator 60 days before the test.	No.
§63.7(b)(2)	Notification of Rescheduling	If rescheduling a performance test is necessary, must notify Administrator 5 days before scheduled date of rescheduled date.	Yes.
§63.7(c)	Quality Assurance/Test Plan	Requirement to submit site-specific test plan 60 days before the test or on date Administrator agrees with: test plan approval procedures; and performance audit requirements; and internal and external QA procedures for testing.	Yes
§63.7(d)	Testing Facilities	Requirements for testing facilities	Yes.

Citation	Subject	Brief description	Applicable
§63.7(e)(1)	Conditions for Conducting Performance Tests.	1. Performance tests must be conducted under representative conditions; and	No.
		2. Cannot conduct performance tests during SSM; and	Yes.
		3. Not a deviation to exceed standard during SSM; and	Yes.
		4. Upon request of Administrator, make available records necessary to determine conditions of performance tests.	Yes.
§63.7(e)(2)	Conditions for Conducting Performance Tests.	Must conduct according to rule and EPA test methods unless Administrator approves alternative.	Yes.
§63.7(e)(3)	Test Run Duration	Must have three separate test runs; and Compliance is based on arithmetic mean of three runs; and conditions when data from an additional test run can be used.	Yes.
§63.7(e)(4)	Interaction with other sections of the Act..	Nothing in §63.7(e)(1) through (4) can abrogate the Administrator's authority to require testing under Section 114 of the Act.	Yes.
§63.7(f)	Alternative Test Method....................	Procedures by which Administrator can grant approval to use an alternative test method.	Yes.
§63.7(g).....................	Performance Test Data Analysis	Must include raw data in performance test report; and must submit performance test data 60 days after end of test with the Notification of Compliance Status; and keep data for 5 years.	Yes.
§63.7(h).....................	Waiver of Tests	Procedures for Administrator to waive performance test.	Yes.
§63.8(a)(1)	Applicability of Monitoring Requirements.................................	Subject to all monitoring requirements in standard.	Yes.
§63.8(a)(2)	Performance Specifications	Performance Specifications in appendix B of part 60 apply.	Yes.
§63.8(a)(3)	[Reserved].		
§63.8(a)(4)	Monitoring with Flares......................	Unless your rule says otherwise, the requirements for flares in §63.11 apply.	No.
§63.8(b)(1)(i)–(ii)......	Monitoring	Must conduct monitoring according to standard unless Administrator approves alternative.	Yes.
§63.8(b)(1)(iii)	Monitoring	Flares not subject to this section unless otherwise specified in relevant standard.	No.
§63.8(b)(2)–(3)..........	Multiple Effluents and Multiple Monitoring Systems	Specific requirements for installing monitoring systems; and must install on each effluent before it is combined and before it is released to the atmosphere unless Administrator approves otherwise; and if more than one monitoring system on an emission point, must report all monitoring system results, unless one monitoring system is a backup.	Yes.
§63.8(c)(1)	Monitoring System Operation and Maintenance.	Maintain monitoring system in a manner consistent with good air pollution control practices.	Yes.
§63.8(c)(1)(i)............	Routine and Predictable SSM	Maintain and operate CMS according to §63.6(e)(1).	Yes.
§63.8(c)(1)(ii)...........	SSM not in SSMP	Must keep necessary parts available for routine repairs of CMSs.	Yes.
§63.8(c)(1)(iii)	Compliance with Operation and Maintenance Requirements.	Must develop and implement an SSMP for CMSs.	Yes.
§63.8(c)(2)–(3)..........	Monitoring System Installation	Must install to get representative emission and parameter measurements; and must verify operational status before or at performance test.	Yes.
§63.8(c)(4)	Continuous Monitoring System (CMS) Requirements.	CMSs must be operating except during breakdown, out-of-control, repair, maintenance, and high-level calibration drifts.	No.
§63.8(c)(4)(i)............	Continuous Monitoring System (CMS) Requirements.	Continuous opacity monitoring system must have a minimum of one cycle of sampling and analysis for each successive 10-second period and one cycle of data recording for each successive 6 minute period.	Yes.
§63.8(c)(4)(ii)...........	Continuous Monitoring System (CMS) Requirements.	Continuous emissions monitoring system must have a minimum of one cycle of operation for each successive 15 minute period.	No.
§63.8(c)(5)	Continuous Opacity Monitoring system (COMS) Requirements.	Must do daily zero and high level calibrations.	Yes.
§63.8(c)(6)	Continuous Monitoring System (CMS) Requirements.	Must do daily zero and high level calibrations.	No.
§63.8(c)(7)–(8)..........	Continuous Monitoring Systems Requirements.	Out-of-control periods, including reporting.	Yes.

Citation	Subject	Brief description	Applicable
§63.8(d)	Continuous Monitoring Systems Quality Control.	Requirements for continuous monitoring systems quality control, including calibration, etc.; and must keep quality control plan on record for the life of the affected source. Keep old versions for 5 years after revisions.	Yes.
§63.8(e)	Continuous monitoring systems Performance Evaluation.	Notification, performance evaluation test plan, reports.	Yes.
§63.8(f)(1)–(5)	Alternative Monitoring Method	Procedures for Administrator to approve alternative monitoring.	Yes
§63.8(f)(6)	Alternative to Relative Accuracy Test	Procedures for Administrator to approve alternative relative accuracy tests for continuous emissions monitoring system.	No.
§63.8(g)(1)–(4)	Data Reduction	Continuous opacity monitoring system 6 minute averages calculated over at least 36 evenly spaced data points; and continuous emissions monitoring system 1-hour averages computed over at least 4 equally spaced data points.	Yes
§63.8(g)(5)	Data Reduction	Data that cannot be used in computing averages for continuous emissions monitoring system and continuous opacity monitoring system.	No.
§63.9(a)	Notification Requirements	Applicability and State Delegation	Yes.
§63.9(b)(1)–(5)	Initial Notifications	Submit notification 120 days after effective date; and Notification of intent to construct/reconstruct; and Notification of commencement of construct/reconstruct; Notification of startup; and Contents of each.	Yes
§63.9(c)	Request for Compliance Extension	Can request if cannot comply by date or if installed BACT/LAER.	Yes.
§63.9(d)	Notification of Special Compliance Requirements for New Source.	For sources that commence construction between proposal and promulgation and want to comply 3 years after effective date.	Yes
§63.9(e)	Notification of Performance Test	Notify Administrator 60 days prior	No.
§63.9(f)	Notification of VE/Opacity Test	Notify Administrator 30 days prior	No.
§63.9(g)	Additional Notifications When Using Continuous Monitoring Systems.	Notification of performance evaluation; and notification using continuous opacity monitoring system data; and notification that exceeded criterion for relative accuracy.	Yes
§63.9(h)(1)–(6)	Notification of Compliance Status	Contents; and due 60 days after end of performance test or other compliance demonstration, and when to submit to Federal vs. State authority.	Yes
§63.9(i)	Adjustment of Submittal Deadlines	Procedures for Administrator to approve change in when notifications must be submitted.	Yes
§63.9(j)	Change in Previous Information	Must submit within 15 days after the change.	Yes
§63.10(a)	Recordkeeping/Reporting	Applies to all, unless compliance extension; and when to submit to Federal vs. State authority; and procedures for owners of more than 1 source.	Yes
§63.10(b)(1)	Recordkeeping/Reporting	General Requirements; and keep all records readily available and keep for 5 years.	Yes
§63.10(b)(2)(i)–(v)	Records related to Startup, Shutdown, and Malfunction.	Occurrence of each of operation (process, equipment); and occurrence of each malfunction of air pollution equipment; and maintenance of air pollution control equipment; and actions during startup, shutdown, and malfunction.	Yes
§63.10(b)(2)(vi) and (x–xi)	Continuous monitoring systems Records	Malfunctions, inoperative, out-of-control; and calibration checks; and adjustments, maintenance.	Yes
§63.10(b)(2)(vii)–(ix)	Records	Measurements to demonstrate compliance with emission limitations; and performance test, performance evaluation, and visible emission observation results; and measurements to determine conditions of performance tests and performance evaluations.	Yes
§63.10(b)(2)(xii)	Records	Records when under waiver	Yes.
§63.10(b)(2)(xiii)	Records	Records when using alternative to relative accuracy test.	No.
§63.10(b)(2)(xiv)	Records	All documentation supporting Initial Notification and Notification of Compliance Status.	Yes.
§63.10(b)(3)	Records	Applicability Determinations	Yes.
§63.10(c)(1),(5)–(8),(10)–(15)	Records	Additional Records for continuous monitoring systems.	Yes
§63.10(c)(7)–(8)	Records	Records of excess emissions and parameter monitoring exceedances for continuous monitoring systems.	No
§63.10(d)(1)	General Reporting Requirements	Requirement to report	Yes

Citation	Subject	Brief description	Applicable
§63.10(d)(2)	Report of Performance Test Results.	When to submit to Federal or State authority.	Yes.
§63.10(d)(3)	Reporting Opacity or VE Observations	What to report and when	Yes.
§63.10(d)(4)	Progress Reports	Must submit progress reports on schedule if under compliance extension.	Yes.
§63.10(d)(5)	Startup, Shutdown, and Malfunction Reports.	Contents and submission	Yes.
§63.10(e)(1)(2)	Additional continuous monitoring systems Reports.	Must report results for each CEM on a unit; and written copy of performance evaluation; and 3 copies of continuous opacity monitoring system performance evaluation.	Yes.
§63.10(e)(3)	Reports	Excess Emission Reports	No.
§63.10(e)(3)(i–iii)	Reports	Schedule for reporting excess emissions and parameter monitor exceedance (now defined as deviations).	No.
§63.10(e)(3)(iv–v)	Excess Emissions Reports	Requirement to revert to quarterly submission if there is an excess emissions and parameter monitor exceedance (now defined as deviations); and provision to request semiannual reporting after compliance for one year; and submit report by 30th day following end of quarter or calendar half; and if there has not been an exceedance or excess emission (now defined as deviations), report contents is a statement that there have been no deviations.	No.
§63.10(e)(3)(iv–v)	Excess Emissions Reports	Must submit report containing all of the information in §63.10(c)(5–13), §63.8(c)(7–8).	No.
§63.10(e)(3)(vi–viii)	Excess Emissions Report and Summary Report	Requirements for reporting excess emissions for continuous monitoring systems (now called deviations); Requires all of the information in §63.10(c)(5– 13), §63.8(c)(7–8).	No.
§63.10(e)(4)	Reporting continuous opacity monitoring system data.	Must submit continuous opacity monitoring system data with performance test data.	Yes.
§63.10(f)	Waiver for Recordkeeping/Reporting	Procedures for Administrator to waive	Yes.
§63.11	Flares	Requirements for flares	No.
§63.12	Delegation	State authority to enforce standards	Yes.
§63.13	Addresses	Addresses where reports, notifications, and requests are sent.	Yes
§63.14	Incorporation by Reference	Test methods incorporated by reference	Yes.
§63.15	Availability of Information	Public and confidential Information	Yes.

Appendix A to Subpart DDDDD—Methodology and Criteria for Demonstrating Eligibility for the Health-Based Compliance Alternatives Specified for the Large Solid Fuel Subcategory

1. Purpose/Introduction

This appendix provides the methodology and criteria for demonstrating that your affected source is eligible for the compliance alternative for the HCl emission limit and/or the total selected metals (TSM) emission limit. This appendix specifies emissions testing methods that you must use to determine HCl, chlorine, and manganese emissions from the affected units and what parts of the affected source facility must be included in the eligibility demonstration. You must demonstrate that your affected source is eligible for the health-based compliance alternatives using either a lookup table analysis (based on the look-up tables included in this appendix) or a site-specific compliance demonstration performed according to the criteria specified in this appendix. This appendix also specifies how and when you file any eligibility demonstrations for your affected source and how to show that your affected source remains eligible for the health-based compliance alternatives in the future.

2. Who Is Eligible To Demonstrate That They Qualify for the Health-Based Compliance Alternatives?

Each new, reconstructed, or existing affected source may demonstrate that they are eligible for the health-based compliance alternatives. Section 63.7490 of subpart DDDDD defines the affected source and explains which affected sources are new, existing, or reconstructed.

3. What Parts of My Facility Have To Be Included in the Health-Based Eligibility Demonstration?

If you are attempting to determine your eligibility for the compliance alternative for HCl, you must include every emission point subject to subpart DDDDD that emits either HCl or Cl_2 in the eligibility demonstration.

If you are attempting to determine your eligibility for the compliance alternative for TSM, you must include every emission point subject to subpart DDDDD that emits manganese in the eligibility demonstration.

4. How Do I Determine HAP Emissions From My Affected Source?

(a) You must conduct HAP emissions tests or fuel analysis for every emission point covered under subpart DDDDD within the affected source facility according to the requirements in paragraphs (b) through (f) of this section and the methods specified in Table 1 of this appendix.

(1) If you are attempting to determine your eligibility for the compliance alternative for HCl, you must test the subpart DDDDD units. at your facility for both HCl and Cl_2. When conducting fuel analysis, you must assume any chlorine detected will be emitted as Cl_2.

(2) If you are attempting to determine your eligibility for the compliance alternative for TSM, you must test the subpart DDDDD units at your facility for manganese.

(b) *Periods when emissions tests must be conducted.*

(1) You must not conduct emissions tests during periods of startup, shutdown, or malfunction, as specified in §63.7(e)(1).

(2) You must test under worst-case operating conditions as defined in this appendix. You must describe your worst-case operating

conditions in your performance test report for the process and control systems (if applicable) and explain why the conditions are worst-case.

(c) *Number of test runs.* You must conduct three separate test runs for each test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour.

(d) *Sampling locations.* Sampling sites must be located at the outlet of the control device and prior to any releases to the atmosphere.

(e) *Collection of monitoring data for HAP control devices.* During the emissions test, you must collect operating parameter monitoring system data at least every 15 minutes during the entire emissions test and establish the site-specific operating requirements in Tables 3 or 4, as appropriate, of subpart DDDDD using data from the monitoring system and the procedures specified in §63.7530 of subpart DDDDD.

(f) *Nondetect data.* You may treat emissions of an individual HAP as zero if all of the test runs result in a nondetect measurement and the condition in paragraph (f)(1) of this section is met for the manganese test method. Otherwise, nondetect data for individual HAP must be treated as one-half of the method detection limit.

(1) For manganese measured using Method 29 in appendix A to 40 CFR part 60, you analyze samples using atomic absorption spectroscopy (AAS).

(g) You must determine the maximum hourly emission rate for each appropriate emission point according to Equation 1 of this appendix.

$$\text{Max Hourly Emissions} = \sum_{i=1}^{n} (Er \times Hm) \quad \text{(Eq. 1)}$$

Where:

Max Hourly Emissions = Maximum hourly emissions for hydrogen chloride, chlorine, or manganese, in units of pounds per hour.

Er = Emission rate (the 3-run average as determined according to Table 1 of this appendix or the pollutant concentration in the fuel samples analyzed according to §63.7521) for hydrogen chloride, chlorine, or manganese, in units of pounds per million Btu of heat input.

Hm = Maximum rated heat input capacity of appropriate emission point, in units of million Btu per hour.

5. What Are the Criteria for Determining If My Facility Is Eligible for the Health-Based Compliance Alternatives?

(a) Determine the HAP emissions from each appropriate emission point within the affected source facility using the procedures specified in section 4 of this appendix.

(b) Demonstrate that your facility is eligible for either of the health-based compliance alternatives using either the methods described in section 6 of this appendix (look-up table analysis) or section 7 of this appendix (site-specific compliance demonstration).

(c) Your facility is eligible for the health-based compliance alternative for HCl if one of the following two statements is true:

(1) The calculated HCl-equivalent emission rate is below the appropriate value in the look-up table;

(2) Your site-specific compliance demonstration indicates that your maximum HI for HCl and Cl_2 at a location where people live is less than or equal to 1.0;

(d) Your facility is eligible for the health-based compliance alternative for TSM if one of the following two statements is true:

(1) The manganese emission rate for all your subpart DDDDD sources is below the appropriate value in the look-up table;

(2) Your site-specific compliance demonstration indicates that your maximum HQ for manganese at a location where people live is less than or equal to 1.0.

6. How Do I Conduct a Look-Up Table Analysis?

You may use look-up tables to demonstrate that your facility is eligible for either the compliance alternative for the HCl emission limit or the compliance alternative for TSM emission limit.

(a) *HCl health-based compliance alternative.* (1) To calculate the total toxicity-weighted HCl-equivalent emission rate for your facility, first calculate the total affected source emission rate of HCl by summing the maximum hourly HCl emission rates from all your subpart DDDDD sources. Then, similarly, calculate the total affected source emission rate for Cl_2. Finally, calculate the toxicity-weighted emission rate (expressed in HCl equivalents) according to Equation 2 of this appendix.

$$ER_{tw} = \sum \left(ER_i \times \left(RfC_{HCl}/RfC_i\right)\right) \quad \text{(Eq. 2)}$$

Where:

ER_{tw} is the HCl-equivalent emission rate, lb/hr.

ER_i is the emission rate of HAP i in lbs/hr

RfC_i is the reference concentration of HAP i

RfC_{HCl} is the reference concentration of HCl (RfCs for HCl and Cl_2 can be found at *http://www.epa.gov/ttn/atw/toxsource/summary.html*).

(2) The calculated HCl-equivalent emission rate will then be compared to the appropriate allowable emission rate in Table 2 of this appendix. To determine the correct value from the table, an average value for the appropriate subpart DDDDD emission points should be used for stack height and the minimum distance between any appropriate subpart DDDDD stack at the facility and the property boundary should be used for property boundary distance. Appropriate emission points and stacks are those that emit HCl and/or Cl_2. If one or both of these values does not match the exact values in the lookup tables, then use the next lowest table value. (**Note:** If your average stack height is less than 5 meters, you must use the 5 meter row.) Your facility is eligible to comply with the health-based alternative HCl emission limit if your toxicity-weighted HCl equivalent emission rate, determined using the methods specified in this appendix, does not exceed the appropriate value in Table 2 of this appendix.

(b) *TSM Compliance Alternative.* To calculate the total manganese emission rate for your affected source, sum the maximum hourly manganese emission rates for all your subpart DDDDD sources. The calculated manganese emission rate will then be compared to the allowable emission rate in the Table 3 of this appendix. To determine the correct value from the table, an average value for the appropriate subpart DDDDD emission points should be used for stack height and the minimum distance between any appropriate subpart DDDDD stack at the facility and the property boundary should be used for property boundary distance. Appropriate emission points and stacks are those that emit manganese. If one or both of these values does not match the exact values in the lookup tables, then use the next lowest table value. (**Note:** If your average stack height is less than 5 meters, you must use the 5 meter row.) Your facility may exclude manganese when demonstrating compliance with the TSM emission limit if your manganese emission rate, determined using the methods specified in this appendix, does not exceed the appropriate value specified in Table 3 of this appendix.

7. How Do I Conduct a Site-Specific Compliance Demonstration?

If you fail to demonstrate that your facility is able to comply with one or both of the alternative health-based emission standards using the look-up table approach, you may choose to perform a site-specific compliance demonstration for your facility. You may use any scientifically-accepted peer-reviewed risk assessment methodology for your site-specific compliance demonstration. An example of one approach for performing a site-specific compliance demonstration for air toxics can be found in the EPA's "Air Toxics Risk Assessment Reference Library, Volume 2, Site-Specific Risk Assessment Technical Resource Document", which may be obtained through the EPA's Air Toxics Web site at *http://www.epa.gov/ttn/fera/ risk_atoxic.html*

(a) Your facility is eligible for the HCl alternative compliance option if your site-specific compliance demonstration shows that the maximum HI for HCl and Cl_2 from your subpart DDDDD sources is less than or equal to 1.0.

(b) Your facility is eligible for the TSM alternative compliance option if your site-specific compliance demonstration shows that the maximum HQ for manganese from your subpart DDDDD sources is less than or equal to 1.0.

(c) At a minimum, your site-specific compliance demonstration must:

(1) Estimate long-term inhalation exposures through the estimation of annual or multi-year average ambient concentrations;

(2) Estimate the inhalation exposure for the individual most exposed to the facility's emissions;

(3) Use site-specific, quality-assured data wherever possible;

(4) Use health-protective default assumptions wherever site-specific data are not available, and;

(5) Contain adequate documentation of the data and methods used for the assessment so that it is transparent and can be reproduced by an experienced risk assessor and emissions measurement expert.

(d) Your site-specific compliance demonstration need not:

(1) Assume any attenuation of exposure concentrations due to the penetration of outdoor pollutants into indoor exposure areas;

(2) Assume any reaction or deposition of the emitted pollutants during transport from the emission point to the point of exposure.

8. What Must My Health-Based Eligibility Demonstration Contain?

(a) Your health-based eligibility demonstration must contain, at a minimum, the information specified in paragraphs (a)(1) through (6) of this section.

(1) Identification of each appropriate emission point at the affected source facility, including the maximum rated capacity of each appropriate emission point.

(2) Stack parameters for each appropriate emission point including, but not limited to, the parameters listed in paragraphs (a)(2)(i) through (iv) below:

(i) Emission release type.

(ii) Stack height, stack area, stack gas temperature, and stack gas exit velocity.

(iii) Plot plan showing all emission points, nearby residences, and fenceline.

(iv) Identification of any control devices used to reduce emissions from each appropriate emission point.

(3) Emission test reports for each pollutant and appropriate emission point which has been tested using the test methods specified in Table 1 of this appendix, including a description of the process parameters identified as being worst case. Fuel analyses for each fuel and emission point which has been conducted including collection and analytical methods used.

(4) Identification of the RfC values used in your look-up table analysis or site-specific compliance demonstration.

(5) Calculations used to determine the HCl-equivalent or manganese emission rates according to sections 6(a) or (b) of this appendix.

(6) Identification of the controlling process factors (including, but not limited to, fuel type, heat input rate, type of control devices, process parameters reflecting the emissions rates used for your eligibility demonstration) that will become Federally enforceable permit conditions used to show that your facility remains eligible for the health-based compliance alternatives.

(b) If you use the look-up table analysis in section 6 of this appendix to demonstrate that your facility is eligible for either health-based compliance alternative, your eligibility demonstration must contain, at a minimum, the information in paragraphs (a) and (b)(1) through (3) of this section.

(1) Calculations used to determine the average stack height of the subpart DDDDD emission points that emit either manganese or HCl and Cl_2.

(2) Identification of the subpart DDDDD emission point, that emits either manganese or HCl and Cl_2, with the minimum distance to the property boundary of the facility.

(3) Comparison of the values in the look-up tables (Tables 2 and 3 of this appendix) to your maximum HCl-equivalent or manganese emission rates.

(c) If you use a site-specific compliance demonstration as described in section 7 of this appendix to demonstrate that your facility is eligible, your eligibility demonstration must contain, at a minimum, the information in paragraphs (a) and (c)(1) through (7) of this section:

(1) Identification of the risk assessment methodology used.

(2) Documentation of the fate and transport model used.

(3) Documentation of the fate and transport model inputs, including the information described in paragraphs (a)(1) through (5) of this section converted to the dimensions required for the model and all of the following that apply: meteorological data; building, land use, and terrain data; receptor locations and population data; and other facility-specific parameters input into the model.

(4) Documentation of the fate and transport model outputs.

(5) Documentation of any exposure assessment and risk characterization calculations.

(6) Comparison of the HQ HI to the limit of 1.0.

9. When Do I Have to Complete and Submit My Health-Based Eligibility Demonstration?

(a) If you have an existing affected source, you must complete and submit your eligibility demonstration to your permitting authority, along with a signed certification that the demonstration is an accurate depiction of your facility, no later than the date one year prior to the compliance date of subpart DDDDD. A separate copy of the eligibility demonstration must be submitted to: U.S. EPA, Risk and Exposure Assessment Group, Emission Standards Division (C404– 01), Attn: Group Leader, Research Triangle Park, North Carolina 27711, electronic mail address *REAG@epa.gov*.

(b) If you have a new or reconstructed affected source that starts up before the effective date of subpart DDDDD, or an affected source that is an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP before the effective date of subpart DDDDD, then you must comply with the requirements of subpart DDDDD until your eligibility demonstration is completed and submitted to your permitting authority.

(c) If you have a new or reconstructed affected source that starts up after the effective date of subpart DDDDD, or an affected source that is an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP after the effective date for subpart DDDDD, then you must follow the schedule in paragraphs (c)(1) and (2) of this section.

(1) You must complete and submit a preliminary eligibility demonstration based on the information (*e.g.*, equipment types, estimated emission rates, etc.) used to obtain your title V permit. You must base your preliminary eligibility demonstration on the maximum emissions allowed under your title V permit. If the preliminary eligibility demonstration indicates that your affected source facility is eligible for either compliance alternative, then you may start up your new affected source and your new affected source will be considered in compliance with the alternative HCl standard and subject to the compliance requirements in this appendix or, in the case of manganese, your compliance demonstration with the TSM emission limit is based on 7 metals (excluding manganese).

(2) You must conduct the emission tests or fuel analysis specified in section 4 of this appendix upon initial startup and use the results of these emissions tests to complete and submit your eligibility demonstration within 180 days following your initial startup

date. To be eligible, you must meet the criteria in section 11 of this appendix within 18 months following initial startup of your affected source.

10. When Do I Become Eligible for the Health-Based Compliance Alternatives?

To be eligible for either health-based compliance alternative, the parameters that defined your affected source as eligible for the health-based compliance alternatives (including, but not limited to, fuel type, fuel mix (annual average), type of control devices, process parameters reflecting the emissions rates used for your eligibility demonstration) must be submitted for incorporation as Federally enforceable limits into your title V permit. If you do not meet these criteria, then your affected source is subject to the applicable emission limits, operating limits, and work practice standards in Subpart DDDDD.

11. How Do I Ensure That My Facility Remains Eligible for the Health-Based Compliance Alternatives?

(a) You must update your eligibility demonstration and resubmit it each time you have a process change, such that any of the parameters that defined your affected source changes in a way that could result in increased HAP emissions (including, but not limited to, fuel type, fuel mix (annual average), change in type of control device, changes in process parameters documented as worst-case conditions during the emissions testing used for your approved eligibility demonstration).

(b) If you are updating your eligibility demonstration to account for an action in paragraph (a) of this section, then you must perform emission testing or fuel analysis according to section 4 of this appendix for the subpart DDDDD emission points that may have increased HAP emissions beyond the levels reflected in your previously approved eligibility demonstration due to the process change. You must submit your revised eligibility demonstration to the permitting authority prior to revising your permit to incorporate the process change. If your updated eligibility demonstration indicates that your affected source is no longer eligible for the health-based compliance alternatives, then you must comply with the applicable emission limits, operating limits, and compliance requirements in Subpart DDDDD prior to making the process change and revising your permit.

12. What Records Must I Keep?

You must keep records of the information used in developing the eligibility demonstration for your affected source, including all of the information specified in section 8 of this appendix.

13. Definitions

The definitions in §63.7575 of subpart DDDDD apply to this appendix. Additional definitions applicable for this appendix are as follows:

Hazard Index (HI) means the sum of more than one hazard quotient for multiple substances and/or multiple exposure pathways.

Hazard Quotient (HQ) means the ratio of the predicted media concentration of a pollutant to the media concentration at which no adverse effects are expected. For inhalation exposures, the HQ is calculated as the air concentration divided by the RfC.

Look-up table analysis means a risk screening analysis based on comparing the HAP or HAP-equivalent emission rate from the affected source to the appropriate maximum allowable HAP or HAP-equivalent emission rates specified in Tables 2 and 3 of this appendix.

Reference Concentration (RfC) means an estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime. It can be derived from various types of human or animal data, with uncertainty factors generally applied to reflect limitations of the data used.

Worst-case operating conditions means operation of an affected unit during emissions testing under the conditions that result in the highest HAP emissions or that result in the emissions stream composition (including HAP and non-HAP) that is most challenging for the control device if a control device is used. For example, worst-case conditions could include operation of an affected unit firing solid fuel likely to produce the most HAP.

TABLE 1 TO APPENDIX B OF SUBPART DDDDD—EMISSION TEST METHODS

For ...	You must ...	Using ...
(1) Each subpart DDDDD emission point for which you choose to use a compliance alternative.	Select sampling ports' location and the number of traverse points.	Method 1 of 40 CFR part 60, appendix A.
(2) Each subpart DDDDD emission point for which you choose to use a compliance alternative.	Determine velocity and volumetric flow rate; ...	Method 2, 2F, or 2G in appendix A to 40 CFR part 60.
(3) Each subpart DDDDD emission point for which you choose to use a compliance alternative.	Conduct gas molecular weight analysis	Method 3A or 3B in appendix A to 40 CFR part 60.
(4) Each subpart DDDDD emission point for which you choose to use a compliance alternative.	Measure moisture content of the stack gas	Method 4 in appendix A to 40 CFR part 60.
(5) Each subpart DDDDD emission point for which you choose to use the HCl compliance alternative.	Measure the hydrogen chloride and chlorine emission concentrations.	Method 26 or 26A in appendix A to 40 CFR part 60.
(6) Each subpart DDDDD emission point for which you choose to use the TSM compliance alternative.	Measure the manganese emission concentration.	Method 29 in appendix A to 40 CFR part 60.
(7) Each subpart DDDDD emission point for which you choose to use a compliance alternative.	Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology in appendix A to part 60 of this chapter.

TABLE 2 TO APPENDIX A OF SUBPART DDDDD—ALLOWABLE TOXICITY-WEIGHTED EMISSION RATE EXPRESSED IN HCl EQUIVALENTS (lbs/hr)

Stack ht.	Distance to property boundary (m)											
(m)	0	50	100	150	200	250	500	1000	1500	2000	3000	5000
5	114.9	114.9	114.9	114.9	114.9	114.9	144.3	287.3	373.0	373.0	373.0	373 0
10	188.5	188.5	188.5	188.5	188.5	188.5	195.3	328.0	432.5	432.5	432.5	432.5
20	386.1	386.1	386.1	386.1	386.1	386.1	386.1	425.4	580.0	602.7	602.7	602 7
30	396.1	396.1	396.1	396.1	396.1	396.1	396.1	436.3	596.2	690.6	807.8	816 5

40	408.1	408.1	408.1	408.1	408.1	408.1	408.1	448.2	613.3	715.5	832.2	966.0
50	421.4	421.4	421.4	421.4	421.4	421.4	421.4	460.6	631.0	746.3	858.2	1002.8
60	435.5	435.5	435.5	435.5	435.5	435.5	435.5	473.4	649.0	778.6	885.0	1043.4
70	450.2	450.2	450.2	450.2	450.2	450.2	450.2	486.6	667.4	813.8	912.4	1087.4
80	465.5	465.5	465.5	465.5	465.5	465.5	465.5	500.0	685.9	849.8	940.9	1134.8
100	497.5	497.5	497.5	497.5	497.5	497.5	497.5	527.4	723.6	917.1	1001.2	1241.3
200	677.3	677.3	677.3	677.3	677.3	677.3	677.3	682.3	919.8	1167.1	1390.4	1924.6

TABLE 3 TO APPENDIX A OF SUBPART DDDDD—ALLOWABLE MANGANESE EMISSION RATE (lbs/hr)

Stack ht. (m)	Distance to property boundary (m)											
	0	50	100	150	200	250	500	1000	1500	2000	3000	5000
5	0.29	0.29	0.29	0.29	0.29	0.29	0.36	0.72	0.93	0.93	0.93	0.94
10	0.47	0.47	0.47	0.47	0.47	0.47	0.49	0.82	1.08	1.08	1.08	1.08
20	0.97	0.97	0.97	0.97	0.97	0.97	0.97	1.06	1.45	1.51	1.51	1.51
30	0.99	0.99	0.99	0.99	0.99	0.99	0.99	1.09	1.49	1.72	2.02	2.04
40	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.12	1.53	1.79	2.08	2.42
50	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.15	1.58	1.87	2.15	2.51
60	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.18	1.62	1.95	2.21	2.61
70	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.22	1.67	2.03	2.28	2.72
80	1.16	1.16	1.16	1.16	1.16	1.16	1.16	1.25	1.71	2.12	2.35	2.84
100	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.32	1.81	2.29	2.50	3.10
200	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.71	2.30	2.92	3.48	4.81

Appendix G

Chapter 7, Section 3, Compliance Assurance Monitoring

(a) Definitions. For purposes of this section:

"Act" means the Clean Air Act, as amended by Pub.L. 101-549, 42 U.S.C. 7401, et seq.

"Applicable requirement" means all of the following as they apply to emissions units at a source subject to this section (including requirements with future effective compliance dates that have been promulgated or approved by the EPA or the State through rulemaking at the time of issuance of the operating permit):

(i) Any standard or other requirement provided for in the Wyoming implementation plan approved or promulgated by the EPA under title I of the Act that implements the relevant requirements of the Act, including any revisions to the plan promulgated in 40 CFR part 52;

(ii) Any standards or requirements in the WAQSR which are not a part of the approved Wyoming implementation plan and are not federally enforceable;

(iii) Any term or condition of any preconstruction permits issued pursuant to regulations approved or promulgated through rulemaking under title I, including parts C or D of the Act and including Chapter 5, Section 2 and Chapter 6, Sections 2 and 4 of the WAQSR;

(iv) Any standard or other requirement promulgated under section 111 of the Act, including section 111(d) and Chapter 5, Section 2 of the WAQSR;

(v) Any standard or other requirement under section 112 of the Act, including any requirement concerning accident prevention under section 112(r)(7) of the Act and including any regulations promulgated by the EPA and the State pursuant to section 112 of the Act;

(vi) Any standard or other requirement of the acid rain program under title IV of the Act or the regulations promulgated thereunder;

(vii) Any requirements established pursuant to section 504(b) or section 114(a)(3) of the Act concerning enhanced monitoring and compliance certifications;

(viii) Any standard or other requirement governing solid waste incineration, under section 129 of the Act;

(ix) Any standard or other requirement for consumer and commercial products, under section 183(e) of the Act (having to do with the release of volatile organic compounds under ozone control requirements);

(x) Any standard or other requirement of the regulations promulgated to protect stratospheric ozone under title VI of the Act, unless the EPA has determined that such requirements need not be contained in a title V permit;

(xi) Any national ambient air quality standard or increment or visibility requirement under part C of title I of the Act, but only as it would apply to temporary sources permitted pursuant to section 504(e) of the Act; and

(xii) Any state ambient air quality standard or increment or visibility requirement of the WAQSR.

(xiii) Nothing under Chapter 6, Section 3(b)(v) shall be construed as affecting the allowance program and Phase II compliance schedule under the acid rain provision of title IV of the Act.

"Capture system" means the equipment (including but not limited to hoods, ducts, fans, and booths) used to contain, capture and transport a pollutant to a control device.

"Continuous compliance determination method" means a method, specified by the applicable standard or an applicable permit condition, which:

(i) Is used to determine compliance with an emission limitation or standard on a continuous basis, consistent with the averaging period established for the emission limitation or standard; and

(ii) Provides data either in units of the standard or correlated directly with the compliance limit.

"Control device" means equipment, other than inherent process equipment, that is used to destroy or remove air pollutant(s) prior to discharge to the atmosphere. The types of equipment that may commonly be used as control devices include, but are not limited to, fabric filters, mechanical collectors, electrostatic precipitators, inertial separators, afterburners, thermal or catalytic incinerators, adsorption devices (such as carbon beds), condensers, scrubbers (such as wet collection and gas absorption devices), selective catalytic or non-catalytic reduction systems, flue gas recirculation systems, spray dryers, spray towers, mist eliminators, acid plants, sulfur recovery plants, injection systems (such as water, steam, ammonia, sorbent or limestone injection), and combustion devices independent of the particular process being conducted at an emissions unit (e.g., the destruction of emissions achieved by venting process emission streams to flares, boilers or process heaters). For purposes of this part, a control device does not include passive control measures that act to prevent pollutants from forming, such as the use of seals, lids, or roofs to prevent the release of pollutants, use of low-polluting fuel or feedstocks, or the use of combustion or other process design features or characteristics. If an applicable requirement establishes that particular equipment which otherwise meets this definition of a control device does not constitute a control device as applied to a particular pollutant-specific emissions unit, then that definition shall be binding for purposes of this part.

"Data" means the results of any type of monitoring or method, including the results of instrumental or non-instrumental monitoring, emission calculations, manual sampling procedures, recordkeeping procedures, or any other form of information collection procedure used in connection with any type of monitoring or method.

"Emission limitation or standard" means any applicable requirement that constitutes an emission limitation, emission standard, standard of performance or means of emission limitation as defined under the Act. An emission limitation or standard may be expressed in terms of the pollutant, expressed either as a specific quantity, rate or concentration of emissions (e.g., pounds of SO_2 per hour, pounds of SO_2 per million British thermal units of fuel input, kilograms of VOC per liter of applied coating solids, or parts per million by volume of SO_2) or as the relationship of uncontrolled to controlled emissions (e.g., percentage capture and destruction efficiency of VOC or percentage reduction of SO_2). An emission limitation or standard may also be expressed either as a work practice, process or control device parameter, or other form of specific design, equipment, operational, or operation and maintenance requirement. For purposes of this part, an emission limitation or standard shall not include general operation requirements that an owner or operator may be required to meet, such as requirements to obtain a permit, to operate and maintain sources in accordance with good air pollution control practices, to develop and maintain a malfunction abatement plan, to keep records, submit reports, or conduct monitoring.

"Emissions unit" means any part or activity of a stationary source that emits or has the potential to emit any regulated air pollutant or any pollutant listed under section 112(b) of the Act. This term is not meant to alter or affect the definition of the term "unit" for purposes of title IV of the Act.

"Exceedence" shall mean a condition that is detected by monitoring that provides data in terms of an emission limitation or standard and that indicates that emissions (or opacity) are greater than the applicable emission limitation or standard (or less than the applicable standard in the case of a percent reduction requirement) consistent with any averaging period specified for averaging the results of the monitoring.

"Excursion" shall mean a departure from an indicator range established for monitoring under this part, consistent with any averaging period specified for averaging the results of the monitoring.

"Inherent process equipment" means equipment that is necessary for the proper or safe functioning of the process, or material recovery equipment that the owner or operator documents is installed and operated primarily for purposes other than compliance with air pollution regulations. Equipment that must be operated at an efficiency higher than that achieved during normal process operations in order to comply with the applicable emission limitation or standard is not inherent process equipment. For the purposes of this part, inherent process equipment is not considered a control device.

"Major source" means any stationary source (or any group of stationary sources that are located on one or more contiguous or adjacent properties, and are under common control of the same person or persons under common control) belonging to a single major industrial grouping and that is described in paragraphs (i), (ii), or (iii) of this definition. For the purpose of defining "major source", a stationary source or group of stationary sources shall be considered part of a single industrial grouping if all of the pollutant emitting activities at such source or group of sources on contiguous or adjacent properties belong to the same Major Group (i.e., all have the same two-digit code) as described in the Standard Industrial Classification Manual, 1987.

(i) A major source under section 112 of the Act, which is defined as:

(A) For pollutants other than radionuclides, any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit, in the aggregate, 10 tons per year (tpy) or more of any hazardous air pollutant which has been listed pursuant to section 112(b) of the Act, 25 tpy or more of any combination of such hazardous air pollutants, or such lesser quantity as the EPA may establish by rule. Notwithstanding the preceding sentence, emissions from any oil or gas exploration or production well (with its associated equipment) and emissions from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources; or

(B) For radionuclides, "major source" shall have the meaning specified by the EPA by rule.

(ii) A major stationary source of air pollutants, as defined in section 302 of the Act, that directly emits or has the potential to emit, 100 tpy or more of any air pollutant (including any major source of fugitive emissions of any such pollutant, as determined by rule by the EPA). Emissions of air pollutants regulated solely due to section 112(r) of the Act shall not be considered in determining whether a source is a "major source" for purposes of Chapter 6, Section 3 applicability. The fugitive emissions of a stationary source shall not be considered in determining whether it is a major stationary source unless the source belongs to one of the following categories of stationary sources:

(A) Stationary sources listed in Chapter 6, Section 4(a)(i)(a) of the WAQSR; or

(B) Any other stationary source category, which as of August 7, 1980 is being regulated under section 111 or 112 of the Act.

(iii) A major stationary source as defined in part D of title I of the Act (in reference to sources located in non-attainment areas).

"Monitoring" means any form of collecting data on a routine basis to determine or otherwise assess compliance with emission limitations or standards. Recordkeeping may be considered monitoring where such records are used to determine or assess compliance with an emission limitation or standard (such as records of raw material content and usage, or records documenting compliance with work practice requirements). The conduct of compliance method tests, such as the procedures in 40 CFR part 60, Appendix A, on a routine periodic basis may be considered monitoring (or as a supplement to other monitoring), provided that requirements to conduct such tests on a one-time basis or at such times as a regulatory authority may require on a non-regular basis are not considered monitoring requirements for purposes of this paragraph. Monitoring may include one or more than one of the following data collection techniques, where appropriate for a particular circumstance:

(i) Continuous emission or opacity monitoring systems;

(ii) Continuous process, capture system, control device or other relevant parameter monitoring systems or procedures, including a predictive emission monitoring system;

(iii) Emission estimation and calculation procedures (e.g., mass balance or stoichiometric calculations);

(iv) Maintenance and analysis of records of fuel or raw materials usage;

(v) Recording results of a program or protocol to conduct specific operation and maintenance procedures;

(vi) Verification of emissions, process parameters, capture system parameters, or control device parameters using portable or in situ measurement devices;

(vii) Visible emission observations;

(viii) Any other form of measuring, recording, or verifying on a routine basis emissions, process parameters, capture system parameters, control device parameters or other factors relevant to assessing compliance with emission limitations or standards.

"Operating permit" means any permit or group of permits covering a source under Chapter 6, Section 3, Operating Permits that is issued, renewed, amended, or revised pursuant to Chapter 6, Section 3.

"Operating permit application" shall mean an application (including any supplement to a previously submitted application) that is submitted by the owner or operator in order to obtain a Chapter 6, Section 3, operating permit.

"Owner or operator" means any person who owns, leases, operates, controls or supervises a stationary source subject to this part.

"Pollutant-specific emissions unit" means an emissions unit considered separately with respect to each regulated air pollutant.

"Potential to emit" means the maximum capacity of a stationary source to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation is enforceable by the EPA and the Division. This term does not alter or affect the use of this term for any other purposes under the Act, or the term "capacity factor" as used in title IV of the Act or the regulations promulgated thereunder.

"Predictive emission monitoring system (PEMS)" means a system that uses process and other parameters as inputs to a computer program or other data reduction system to produce values in terms of the applicable emission limitation or standard.

"Regulated air pollutant" means the following:

(i) Nitrogen oxides (NO_x) or any volatile organic compound;

(ii) Any pollutant for which a national ambient air quality standard has been promulgated;

(iii) Any pollutant that is subject to any standard established in Chapter 5, Section 2 of the WAQSR or section 111 of the Act;

(iv) Any Class I or II substance subject to a standard promulgated under or established by title VI of the Act; or

(v) Any pollutant subject to a standard promulgated under section 112 or other requirements established under section 112 of the Act, including sections 112(g), (j), and (r) of the Act, including the following:

(A) Any pollutant subject to requirements under section 112(j) of the Act. If the EPA fails to promulgate a standard by the date established pursuant to section 112(e) of the Act, any pollutant for which a subject source would be major shall be considered to be regulated on the date 18 months after the applicable date established pursuant to section 112(e) of the Act; and

(B) Any pollutant for which the requirements of section 112(g)(2) of the Act have been met, but only with respect to the individual source subject to section 112(g)(2) requirement.

(vi) Pollutants regulated solely under section 112(r) of the Act are to be regulated only with respect to the requirements of section 112(r) for permits issued under Chapter 6, Section 3, Operating Permits.

"Stationary source" means any building, structure, facility, or installation that emits or may emit any regulated air pollutant or any pollutant listed under section 112(b) of the Act.

(b) Applicability.

(i) General applicability. Except for backup utility units that are exempt under paragraph (ii)(B) of this subsection (b), the requirements of this part shall apply to a pollutant-specific emissions unit at a major source that is required to obtain a Chapter 6, Section 3, operating permit if the unit satisfies all of the following criteria:

(A) The unit is subject to an emission limitation or standard for the applicable regulated air pollutant (or a surrogate thereof), other than an emission limitation or standard that is exempt under paragraph (ii)(A) of this subsection (b);

(B) The unit uses a control device to achieve compliance with any such emission limitation or standard; and

(C) The unit has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source. For purposes of this paragraph, "potential pre-control device emissions" shall have the same meaning as "potential to emit", as defined in Chapter 7, Section 3(a), except that emission reductions achieved by the applicable control device shall not be taken into account.

(ii) Exemptions.

(A) Exempt emission limitations or standards. The requirements of this part shall not apply to any of the following emission limitations or standards:

(I) Emission limitations or standards proposed by the EPA Administrator after November 15, 1990 pursuant to section 111 or 112 of the Act;

(II) Stratospheric ozone protection requirements under title VI of the Act;

(III) Acid Rain Program requirements pursuant to sections 404, 405, 406, 407(a), 407(b), or 410 of the Act;

(IV) Emission limitations or standards or other applicable requirements that apply solely under an emissions trading program approved or promulgated by the Administrator under the Act that allows for trading emissions within a source or between sources;

(V) A federally enforceable emissions cap included in the Chapter 6, Section 3 operating permit;

(VI) Emission limitations or standards for which a Chapter 6, Section 3, operating permit specifies a continuous compliance determination method, as defined in Chapter 7, Section 3(a). The exemption provided in (b)(ii)(A)(VI) of this section shall not apply if the applicable compliance method includes an assumed control device emission reduction factor that could be affected by the actual operation and maintenance of the control device (such as a surface coating line controlled by an incinerator for which continuous compliance is determined by calculating emissions on the basis of coating records and an assumed control device efficiency factor based on an initial performance test; in this example, this part would apply to the control device and capture system, but not to the remaining elements of the coating line, such as raw material usage).

(B) Exemption for backup utility power emissions units. The requirements of this part shall not apply to a utility unit, as defined in §72.2 of Chapter 11, Section 2(b) that is municipally-owned if the owner or operator provides documentation in a Chapter 6, Section 3, operating permit application that:

(I) The utility unit is exempt from all monitoring requirements in Chapter 11, Section 2(b), Acid Rain, Continuous emission monitoring (including the appendices thereto);

(II) The utility unit is operated for the sole purpose of providing electricity during periods of peak electrical demand or emergency situations and will be operated consistent with that purpose throughout the Chapter 6, Section 3, operating permit term. The owner or operator shall provide historical operating data and relevant contractual obligations to document that this criterion is satisfied; and

(III) The actual emissions from the utility unit, based on the average annual emissions over the last three calendar years of operation (or such shorter time period that is available for units with fewer than three years of operation) are less than 50 percent of the amount in tons per year required for a source to be classified as a major source and are expected to remain so.

(c) Monitoring design criteria.

(i) General criteria. To provide a reasonable assurance of compliance with emission limitations or standards for the anticipated range of operations at a pollutant-specific emissions unit, monitoring under this part shall meet the following general criteria:

(A) The owner or operator shall design the monitoring to obtain data for one or more indicators of emission control performance for the control device, any associated capture system and, if necessary to satisfy paragraph (c)(i)(B) of this section, processes at a pollutant-specific emissions unit. Indicators of performance may include, but are not limited to, direct or predicted emissions (including visible emissions or opacity), process and control device parameters that affect control device (and capture system) efficiency or emission rates, or recorded findings of inspection and maintenance activities conducted by the owner or operator.

(B) The owner or operator shall establish an appropriate range(s) or designated condition(s) for the selected indicator(s) such that operation within the ranges provides a reasonable assurance of ongoing compliance with emission limitations or standards for the anticipated range of operating conditions. Such range(s) or condition(s) shall reflect the proper operation and maintenance of the control device (and associated capture system), in accordance with applicable design properties, for minimizing emissions over the anticipated range of operating conditions at least to the level required to achieve compliance with the applicable requirements. The reasonable assurance of compliance will be assessed by maintaining performance within the indicator range(s) or designated condition(s). The ranges shall be established in accordance with the design and performance requirements in this section and documented in accordance with the requirements in Chapter 7, Section 3(d). If necessary to assure that the control device and associated capture system can satisfy this criterion, the owner or operator shall monitor appropriate process operational parameters (such as total throughput where necessary to stay within the rated capacity for a control device). In addition, unless specifically stated otherwise by an applicable requirement, the owner or operator shall monitor indicators to detect any bypass of the control device (or capture system) to the atmosphere, if such bypass can occur based on the design of the pollutant-specific emissions unit.

(C) The design of indicator ranges or designated conditions may be:

(I) Based on a single maximum or minimum value if appropriate (e.g., maintaining condenser temperatures a certain number of degrees below the condensation temperature of the applicable compound(s) being processed) or at multiple levels that are relevant to distinctly different operating conditions (e.g., high versus low load levels);

(II) Expressed as a function of process variables (e.g., an indicator range expressed as minimum to maximum pressure drop across a venturi throat in a particulate control scrubber);

(III) Expressed as maintaining the applicable parameter in a particular operational status or designated condition (e.g., position of a damper controlling gas flow to the atmosphere through a by-pass duct);

(IV) Established as interdependent between more than one indicator.

(ii) Performance criteria. The owner or operator shall design the monitoring to meet the following performance criteria:

(A) Specifications that provide for obtaining data that are representative of the emissions or parameters being monitored (such as detector location and installation specifications, if applicable);

(B) For new or modified monitoring equipment, verification procedures to confirm the operational status of the monitoring prior to the date by which the owner or operator must conduct monitoring under this part as specified in Chapter 7, Section 3(g)(i). The owner or operator shall consider the monitoring equipment manufacturer's requirements or recommendations for installation, calibration, and start-up operation;

(C) Quality assurance and control practices that are adequate to ensure the continuing validity of the data. The owner or operator shall consider manufacturer recommendations or requirements applicable to the monitoring in developing appropriate quality assurance and control practices;

(D) Specifications for the frequency of conducting the monitoring, the data collection procedures that will be used (e.g., computerized data acquisition and handling, alarm sensor, or manual log entries based on gauge readings), and, if applicable, the period over which discrete data points will be averaged for the purpose of determining whether an excursion or exceedance has occurred.

(I) At a minimum, the owner or operator shall design the period over which data are obtained and, if applicable, averaged consistent with the characteristics and typical variability of the pollutant-specific emissions unit (including the control device and associated capture system). Such intervals shall be commensurate with the time period over which a change in control device performance that would require actions by owner or operator to return operations within normal ranges or designated conditions is likely to be observed.

(II) For all pollutant-specific emissions units with the potential to emit, calculated including the effect of control devices, the applicable regulated air pollutant in an amount equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source, for each parameter monitored, the owner or operator shall collect four or more data values equally spaced over each hour and average the values, as applicable, over the applicable averaging period as determined in accordance with paragraph (c)(ii)(D)(I) of this section. The Division may approve a reduced data collection frequency, if appropriate, based on information presented by the owner or operator concerning the data collection mechanisms available for a particular parameter for the particular pollutant-specific emissions unit (e.g., integrated raw material or fuel analysis data, noninstrumental measurement of waste feed rate or visible emissions, use of a portable analyzer or an alarm sensor).

(III) For other pollutant-specific emissions units, the frequency of data collection may be less than the frequency specified in subparagraph (c)(ii)(D)(II) of this section but the monitoring shall include some data collection at least once per 24-hour period (e.g., a daily inspection of a carbon adsorber operation in conjunction with a weekly or monthly check of emissions with a portable analyzer).

(iii) Evaluation factors. In designing monitoring to meet the requirements in paragraphs (c)(i) and (c)(ii) of this section, the owner or operator shall take into account site-specific factors including the applicability of existing monitoring equipment and procedures, the ability of the monitoring to account for process and control device operational variability, the reliability and latitude built into the control technology, and the level of actual emissions relative to the compliance limitation.

(iv) Special criteria for the use of continuous emission, opacity or predictive monitoring systems.

(A) If a continuous emission monitoring system (CEMS), continuous opacity monitoring system (COMS) or predictive emission monitoring system (PEMS) is required pursuant to other authority under the Act or state or local law, the owner or operator shall use such system to satisfy the requirements of this section.

(B) The use of a CEMS, COMS, or PEMS that satisfies any of the following monitoring requirements shall be deemed to satisfy the general design criteria in paragraphs (c)(i) and (c)(ii) of this section, provided that a COMS may be subject to the criteria for establishing indicator ranges under paragraph (c)(i) of this section:

(I) Section 51.214 and Appendix P of 40 CFR part 51;

(II) Chapter 5, Section 2(j) and Section 2(b)(i), 40 CFR part 60, Appendix B;

(III) Chapter 5, Section 3(j) and any applicable performance specifications required pursuant to the applicable subpart of Chapter 5, Section 3;

(IV) Chapter 11, Section 2b, Acid Rain, Continuous emission monitoring;

(V) 40 CFR part 266, Subpart H and appendix IX; or

(VI) If an applicable requirement does not otherwise require compliance with the requirements listed in the preceding paragraphs (c)(iv)(B)(I)-(V) of this section, comparable requirements and specifications established by the Division.

(C) The owner or operator shall design the monitoring system subject to subsection (c)(iv) to:

(I) Allow for reporting of exceedances (or excursions if applicable to a COMS used to assure compliance with a particulate matter standard), consistent with any period for reporting of exceedances in an underlying requirement. If an underlying requirement does not contain a provision for establishing an averaging period for the reporting of exceedances or excursions, the criteria used to develop an averaging period in (c)(ii)(D) of this section shall apply; and

(II) Provide an indicator range consistent with paragraph (c)(i) of this section for a COMS used to assure compliance with a particulate matter standard. If an opacity standard applies to the pollutant-specific emissions unit, such limit may be used as the appropriate indicator range unless the opacity limit fails to meet the criteria in paragraph (c)(i) of this section after considering the type of control device and other site-specific factors applicable to the pollutant-specific emissions unit.

(d) Submittal requirements.

(i) The owner or operator shall submit to the Division monitoring that satisfies the design requirements in Chapter 7, Section 3(c). The submission shall include the following information:

(A) The indicators to be monitored to satisfy Chapter 7, Section 3(c)(i)(A)-(B);

(B) The ranges or designated conditions for such indicators, or the process by which such indicator ranges or designated conditions shall be established;

(C) The performance criteria for the monitoring to satisfy Chapter 7, Section 3(c)(ii); and

(D) If applicable, the indicator ranges and performance criteria for a CEMS, COMS or PEMS pursuant to Chapter 7, Section 3(c)(iv).

(ii) As part of the information submitted, the owner or operator shall submit a justification for the proposed elements of the monitoring. If the performance specifications proposed to satisfy Chapter 7, Section 3(c)(ii)(B) or (C) include differences from manufacturer recommendations, the owner or operator shall explain the reasons for the differences between the requirements proposed by the owner or operator and the manufacturer's recommendations or requirements. The owner or operator also shall submit any data supporting the justification, and may refer to generally available sources of information used to support the justification (such as generally available air pollution engineering manuals, or EPA publications on appropriate monitoring for various types of control devices or capture systems). To justify the appropriateness of the monitoring elements proposed, the owner or operator may rely in part on existing applicable requirements that establish the monitoring for the applicable pollutant-specific emissions unit or a similar unit. If an owner or operator relies on presumptively acceptable monitoring, no further justification for the appropriateness of that monitoring should be necessary other than an explanation of the applicability of such monitoring to the unit in question, unless data or information is brought forward to rebut the assumption. Presumptively acceptable monitoring includes:

(A) Presumptively acceptable or required monitoring approaches, established by the Division in a rule that constitutes part of the applicable implementation plan required pursuant to title I of the Act, that are designed to achieve compliance with this section for particular pollutant-specific emissions units;

(B) Continuous emission, opacity or predictive emission monitoring systems that satisfy applicable monitoring requirements and performance specifications as specified in Chapter 7, Section 3(c)(iv);

(C) Excepted or alternative monitoring methods allowed or approved pursuant to Chapter 11, Section 2(b), Acid Rain, Continuous emission monitoring;

(D) Monitoring included for standards exempt from this section pursuant to Chapter 7, Section 3(b)(ii)(A)(I) or (VI) to the extent such monitoring is applicable to the performance of the control device (and associated capture system) for the pollutant-specific emissions unit; and

(E) Presumptively acceptable monitoring identified in guidance by EPA. Such guidance will address the requirements under Chapter 7, Section 3(d)(i),(ii) and (iii) to the extent practicable.

(iii) (A) Except as provided in Chapter 7, Section 3(d)(iv), the owner or operator shall submit control device (and process and capture system, if applicable) operating parameter data obtained during the conduct of the applicable compliance or performance test conducted under conditions specified by the applicable rule. If the applicable rule does not specify testing conditions or only partially specifies test conditions, the performance test generally shall be conducted under conditions representative of maximum emissions potential under anticipated operating conditions at the pollutant-specific emissions unit. Such data may be supplemented, if desired, by engineering assessments and manufacturer's recommendations to justify the indicator ranges (or, if applicable, the procedures for establishing such indicator ranges). Emission testing is not required to be conducted over the entire indicator range or range of potential emissions.

(B) The owner or operator must document that no changes to the pollutant-specific emissions unit, including the control device and capture system, have taken place that could result in a significant change in the control system performance or the selected ranges or designated conditions for the indicators to be monitored since the performance or compliance tests were conducted.

(iv) If existing data from unit-specific compliance or performance testing specified in Chapter 7, Section 3(d)(iii) are not available, the owner or operator:

(A) Shall submit a test plan and schedule for obtaining such data in accordance with Chapter 7, Section 3(d)(v); or

(B) May submit indicator ranges (or procedures for establishing indicator ranges) that rely on engineering assessments and other data, provided that the owner or operator demonstrates that factors specific to the type of monitoring, control device, or pollutant-specific emissions unit make compliance or performance testing unnecessary to establish indicator ranges at levels that satisfy the criteria in Chapter 7, Section 3(c)(i).

(v) If the monitoring submitted by the owner or operator requires installation, testing, or other necessary activities prior to use of the monitoring for purposes of this part, the owner or operator shall include an implementation plan and schedule for installing, testing and performing any other appropriate activities prior to use of the monitoring. The implementation plan and schedule shall provide for use of the monitoring as expeditiously as practicable after approval of the monitoring in the Chapter 6, Section 3 operating permit pursuant to Chapter 7, Section 3(f), but in no case shall the schedule for completing installation and beginning operation of the monitoring exceed 180 days after approval of the permit.

(vi) If a control device is common to more than one pollutant-specific emissions unit, the owner or operator may submit monitoring for the control device and identify the pollutant-specific emissions units affected and any process or associated capture device conditions that must be maintained or monitored in accordance with Chapter 7, Section 3(c)(i) rather than submit separate monitoring for each pollutant-specific emissions unit.

(vii) If a single pollutant-specific emissions unit is controlled by more than one control device similar in design and operation, the owner or operator may submit monitoring that applies to all the control devices and identify the control devices affected and any process or associated capture device conditions that must be maintained or monitored in accordance with Chapter 7, Section 3(c)(i) rather than submit a separate description of monitoring for each control device.

(e) Deadlines for submittals.

(i) Large pollutant-specific emissions units. For all pollutant-specific emissions units with the potential to emit (taking into account control devices to the extent appropriate under the definition of this term in Chapter 7, Section 3(a) the applicable regulated air pollutant in an amount equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source, the owner or operator shall submit the information required under Chapter 7, Section 3(d) at the following times:

(A) On or after April 20, 1998, the owner or operator shall submit information as part of an application for an initial Chapter 6, Section 3 operating permit if, by that date, the application either:

(I) Has not been filed; or

(II) Has not yet been determined to be complete by the Division.

(B) On or after April 20, 1998, the owner or operator shall submit information as part of an application for a significant permit revision under Chapter 6, Section 3, but only with respect to those pollutant-specific emissions units for which the proposed permit revision is applicable.

(C) The owner or operator shall submit any information not submitted under the deadlines set forth in Chapter 7, Section 3(e)(i)(A) and (B) as part of the application for the renewal of a Chapter 6, Section 3 operating permit.

(ii) Other pollutant-specific emissions units. For all other pollutant-specific emissions units subject to this part and not subject to Chapter 7, Section 3(e)(i), the owner or operator shall submit the information required under Chapter 7, Section 3(d) as part of an application for a renewal of a Chapter 6, Section 3 operating permit.

(iii) The effective date for the requirement to submit information under Chapter 7, Section 3(d) shall be as specified pursuant to Chapter 7, Section 3(e)(i)-(iii) and a permit reopening to require the submittal of information under this section shall not be required pursuant to Chapter 6, Section 3(d)(vii)(A)(I), provided, however, that, if a Chapter 6, Section 3 operating permit is reopened for cause by EPA or the Division pursuant to Chapter 6, Section 3(d)(vii)(A)(III) or (IV), the applicable agency may require the submittal of information under this section for those pollutant-specific emissions units that are subject to this part and that are affected by the permit reopening.

(iv) Prior to approval of monitoring that satisfies this part, the owner or operator is subject to the requirements of Chapter 6, Section 3(h)(i)(C)(I)(2.).

(f) Approval of monitoring.

(i) Based on an application that includes the information submitted in accordance with Chapter 7, Section 3(e), the Division shall act to approve the monitoring submitted by the owner or operator by confirming that the monitoring satisfies the requirements in Chapter 7, Section 3(c).

(ii) In approving monitoring under this section, the Division may condition the approval on the owner or operator collecting additional data on the indicators to be monitored for a pollutant-specific emissions unit, including required compliance or performance testing, to confirm the ability of the monitoring to provide data that are sufficient to satisfy the requirements of this part and to confirm the appropriateness of an indicator range(s) or designated condition(s) proposed to satisfy Chapter 7, Section 3(c)(i)(B) and (C) and consistent with the schedule in Chapter 7, Section 3(d)(v).

(iii) If the Division approves the proposed monitoring, the Division shall establish one or more permit terms or conditions that specify the required monitoring in accordance with Chapter 6, Section 3(h)(i)(c)(I). At a minimum, the permit shall specify:

(A) The approved monitoring approach that includes all of the following:

(I) The indicator(s) to be monitored (such as temperature, pressure drop, emissions, or similar parameter);

(II) The means or device to be used to measure the indicator(s) (such as temperature measurement device, visual observation, or CEMS); and

(III) The performance requirements established to satisfy Chapter 7, Section 3(c)(ii) or (iv), as applicable.

(B) The means by which the owner or operator will define an exceedance or excursion for purposes of responding to and reporting exceedances or excursions under Chapter 7, Section 3(g) and (h). The permit shall specify the level at which an excursion or exceedance will be deemed to occur, including the appropriate averaging period associated with such exceedance or excursion. For defining an excursion from an indicator range or designated condition, the permit may either include the specific value(s) or condition(s) at which an excursion shall occur, or the specific procedures that will be used to establish that value or condition. If the latter, the permit shall specify appropriate notice procedures for the owner or operator to notify the Division upon any establishment or reestablishment of the value.

(C) The obligation to conduct the monitoring and fulfill the other obligations specified in Chapter 7, Section 3(g) through (i).

(D) If appropriate, a minimum data availability requirement for valid data collection for each averaging period, and, if appropriate, a minimum data availability requirement for the averaging periods in a reporting period.

(iv) If the monitoring proposed by the owner or operator requires installation, testing or final verification of operational status, the Chapter 6, Section 3 operating permit shall include an enforceable schedule with appropriate milestones for completing such installation, testing, or final verification consistent with the requirements in Chapter 7, Section 3(d)(v).

(v) If the Division disapproves the proposed monitoring, the following applies:

(A) The draft or final permit shall include, at a minimum, monitoring that satisfies the requirements of Chapter 6, Section 3(h)(i)(C)(I)(2.);

(B) The Division shall include in the draft or final permit a compliance schedule for the source owner to submit monitoring that satisfies Chapter 7, Section 3(c) and (d), but in no case shall the owner or operator submit revised monitoring more than 180 days from the date of issuance of the Chapter 6, Section 3 operating permit; and

(C) If the source owner or operator does not submit the monitoring in accordance with the compliance schedule as required in Chapter 7, Section 3(f)(v)(B) or if the Division disapproves the monitoring submitted, the source owner or operator shall be deemed not in compliance with Chapter 7, Section 3, unless the source owner or operator successfully challenges the disapproval.

(g) Operation of approved monitoring.

(i) Commencement of operation. The owner or operator shall conduct the monitoring required under this part upon issuance of a Chapter 6, Section 3 operating permit that includes such monitoring, or by such later date specified in the permit pursuant to Chapter 7, Section 3(f)(v).

(ii) Proper maintenance. At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.

(iii) Continued operation. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(iv) Response to excursions or exceedances.

(A) Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

(B) Determination of whether the owner or operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

(v) Documentation of need for improved monitoring. After approval of monitoring under this part, if the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the Division and, if necessary, submit a proposed modification to the Chapter 6, Section 3 operating permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters

(h) Quality improvement plan (QIP) requirements.

(i) Based on the results of a determination made under Chapter 7, Section 3(g)(iv)(B), the Administrator or the Division may require the owner or operator to develop and implement a QIP. Consistent with Chapter 7, Section 3(f)(iii)(C), the Chapter 6, Section 3 operating permit may specify an appropriate threshold, such as an accumulation of exceedances or excursions exceeding 5 percent duration of a pollutant-specific emissions unit's operating time for a reporting period, for requiring the implementation of a QIP. The threshold may be set at a higher or lower percent or may rely on other criteria for purposes of indicating whether a pollutant-specific emissions unit is being maintained and operated in a manner consistent with good air pollution control practices.

(ii) Elements of a QIP.

(A) The owner or operator shall maintain a written QIP, if required, and have it available for inspection.

(B) The plan initially shall include procedures for evaluating the control performance problems and, based on the results of the evaluation procedures, the owner or operator shall modify the plan to include procedures for conducting one or more of the following actions, as appropriate:

(I) Improved preventive maintenance practices.

(II) Process operation changes.

(III) Appropriate improvements to control methods.

(IV) Other steps appropriate to correct control performance.

(V) More frequent or improved monitoring (only in conjunction with one or more steps under Chapter 7, Section 3(h)(ii)(B)(I) -(IV)).

(iii) If a QIP is required, the owner or operator shall develop and implement a QIP as expeditiously as practicable and shall notify the Division if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.

(iv) Following implementation of a QIP, upon any subsequent determination pursuant to Chapter 7, Section 3(g)(iv)(B), the Administrator or the Division may require that an owner or operator make reasonable changes to the QIP if the QIP is found to have:

(A) Failed to address the cause of the control device performance problems; or

(B) Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

(v) Implementation of a QIP shall not excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act.

(i) Reporting and recordkeeping requirements.

(i) General reporting requirements.

(A) On and after the date specified in Chapter 7, Section 3(g)(i) by which the owner or operator must use monitoring that meets the requirements of this part, the owner or operator shall submit monitoring reports to the Division in accordance with Chapter 6, Section 3(h)(i)(C)(III).

(B) A report for monitoring under this part shall include, at a minimum, the information required under Chapter 6, Section 3(h)(i)(C)(III) and the following information, as applicable:

(I) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;

(II) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

(III) A description of the actions taken to implement a QIP during the reporting period as specified in Chapter 7, Section 3(h). Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

(ii) General recordkeeping requirements.

(A) The owner or operator shall comply with the recordkeeping requirements specified in Chapter 6, Section 3(h)(i)(C)(II). The owner or operator shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to Chapter 7, Section 3(h) and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this part (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).

(B) Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements.

(j) Savings provisions.

(i) Nothing in this part shall:

(A) Excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act. The requirements of this part shall not be used to justify the approval of monitoring less stringent than the monitoring which is required under separate legal authority and are not intended to establish minimum requirements for the purpose of determining the monitoring to be imposed under separate authority under the Act, including monitoring in permits issued pursuant to Chapter 6, Section 2. The purpose of this part is to require, as part of the issuance of a permit under Chapter 6, Section 3, improved or new monitoring at those emissions units where monitoring requirements do not exist or are inadequate to meet the requirements of this part.

(B) Restrict or abrogate the authority of the Administrator or the Division to impose additional or more stringent monitoring, recordkeeping, testing, or reporting requirements on any owner or operator of a source under any provision of the Act, including but not limited to sections 114(a)(1) and 504(b), or state law, as applicable.

(C) Restrict or abrogate the authority of the Administrator or Division to take any enforcement action under the Act for any violation of an applicable requirement or of any person to take action under section 304 of the Act.